BLACK HILLS CORP /SD/
Form 10-Q
May 04, 2012

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

Form 10-Q

x QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the quarterly period ended March 31, 2012

OR

o TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the transition period from __________ to __________.

Commission File Number 001-31303

Black Hills Corporation
Incorporated in South Dakota — IRS Identification Number 46-0458824
625 Ninth Street
Rapid City, South Dakota 57701

Registrant's telephone number (605) 721-1700

Former name, former address, and former fiscal year if changed since last report
NONE

Indicate by check mark whether the Registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the Registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days.
Yes x No o

Indicate by check mark whether the Registrant has submitted electronically and posted on its corporate website, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T during the preceding 12 months (or for such shorter period that the Registrant was required to submit and post such files).
Yes x No o

Indicate by check mark whether the Registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company (as defined in Rule 12b-2 of the Exchange Act).

Large accelerated filer x	Accelerated filer o
Non-accelerated filer o	Smaller reporting company o

Indicate by check mark whether the Registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act).
Yes o No x

Indicate the number of shares outstanding of each of the issuer's classes of common stock as of the latest practicable date.

Class	Outstanding at April 30, 2012
Common stock, $1.00 par value	44,089,428 shares

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GLOSSARY OF TERMS AND ABBREVIATIONS
AND ACCOUNTING STANDARDS

The following terms and abbreviations appear in the text of this report and have the definitions described below:

AFUDC	Allowance for Funds Used During Construction
AOCI	Accumulated Other Comprehensive Income (Loss)
ASC	Accounting Standards Codification
ASU	Accounting Standards Update
Bbl	Barrel
Bcf	Billion cubic feet
Bcfe	Billion cubic feet equivalent
BHC	Black Hills Corporation
BHEP	Black Hills Exploration and Production, Inc., representing our Oil and Gas segment, a direct, wholly-owned subsidiary of Black Hills Non-regulated Holdings
Black Hills Electric Generation	Black Hills Electric Generation, LLC, representing our Power Generation segment, a direct wholly-owned subsidiary of Black Hills Non-regulated Holdings
Black Hills Energy	The name used to conduct the business activities of Black Hills Utility Holdings
Black Hills Non-regulated Holdings	Black Hills Non-regulated Holdings, LLC, a direct, wholly-owned subsidiary of the Company
Black Hills Power	Black Hills Power, Inc., a direct, wholly-owned subsidiary of the Company
Black Hills Service Company	Black Hills Service Company, a direct wholly-owned subsidiary of the Company
Black Hills Utility Holdings	Black Hills Utility Holdings, Inc., a direct, wholly-owned subsidiary of the Company
Black Hills Wyoming	Black Hills Wyoming, LLC, a direct, wholly-owned subsidiary of Black Hills Electric Generation
Btu	British thermal unit
Cheyenne Light	Cheyenne Light, Fuel and Power Company, a direct, wholly-owned subsidiary of the Company
Colorado Electric	Black Hills Colorado Electric Utility Company, LP (doing business as Black Hills Energy), an indirect, wholly-owned subsidiary of Black Hills Utility Holdings
Colorado Gas	Black Hills Colorado Gas Utility Company, LP (doing business as Black Hills Energy), an indirect, wholly-owned subsidiary of Black Hills Utility Holdings
Colorado IPP	Black Hills Colorado IPP, a direct wholly-owned subsidiary of Black Hills Electric Generation
CPCN	Certificate of Public Convenience and Necessity
CPUC	Colorado Public Utilities Commission
CT	Combustion Turbine
CVA	Credit Valuation Adjustment
De-designated interest rate swaps	The $250 million notional amount interest rate swaps that were originally designated as cash flow hedges under accounting for derivatives and hedges but subsequently de-designated.
Dodd-Frank	Dodd-Frank Wall Street Reform and Consumer Protection Act
DRIP	Dividend Reinvestment and Stock Purchase Plan
Dth	Dekatherm. A unit of energy equal to 10 therms or one million British thermal units (MMBtu)

ECA	Energy Cost Adjustment
Enserco	Enserco Energy Inc., representing our Energy Marketing segment, sold February 29, 2012
Equity Forward Instrument	Equity Forward Agreement with J.P. Morgan connected to a public offering of 4,413,519 shares of Black Hills Corporation common stock

FASB	Financial Accounting Standards Board
FDIC	Federal Deposit Insurance Corporation
FERC	Federal Energy Regulatory Commission
GAAP	Generally Accepted Accounting Principles of the United States
Global Settlement	Settlement with the utilities commission where the dollar figure is agreed upon, but the specific adjustments used by each party to arrive at the figure are not specified in public rate orders
IFRS	International Financial Reporting Standards
Iowa Gas	Black Hills Iowa Gas Utility Company, LLC (doing business as Black Hills Energy), a direct, wholly-owned subsidiary of Black Hills Utility Holdings
IPP	Independent Power Producer
IRS	Internal Revenue Service
Kansas Gas	Black Hills Kansas Gas Utility Company, LLC (doing business as Black Hills Energy), a direct, wholly-owned subsidiary of Black Hills Utility Holdings
LIBOR	London Interbank Offered Rate
LOE	Lease Operating Expense
Mcf	One thousand standard cubic feet
Mcfe	One thousand standard cubic feet equivalent. Natural gas liquid is converted by dividing gallons by 7. Crude oil is converted by multiplying by 6.
MMBtu	One million British thermal units
MSHA	Mine Safety and Health Administration
MW	Megawatt
MWh	Megawatt-hour
Nebraska Gas	Black Hills Nebraska Gas Utility Company, LLC (doing business as Black Hills Energy), a direct, wholly-owned subsidiary of Black Hills Utility Holdings
NGL	Natural Gas Liquids
NPSC	Nebraska Public Service Commission
NYMEX	New York Mercantile Exchange
OTC	Over-the-counter
PGA	Purchase Gas Adjustment
PPA	Power Purchase Agreement
Revolving Credit Facility	Our $500 million five-year revolving credit facility which commenced on February 1, 2012 and expires on February 1, 2017
S&P	Standard and Poor's
SEC	United States Securities and Exchange Commission
Twin Eagle	Twin Eagle Resource Management, LLC
WPSC	Wyoming Public Service Commission
WRDC	Wyodak Resources Development Corp., a direct, wholly-owned subsidiary of Black Hills Non-regulated Holdings

BLACK HILLS CORPORATION
CONDENSED CONSOLIDATED STATEMENTS OF INCOME AND COMPREHENSIVE INCOME
(unaudited)

	Three Months Ended March 31,	
	2012	2011
	(in thousands, except per share amounts)	
Revenue:		
Utilities	$336,655	$374,696
Non-regulated energy	29,196	26,139
Total revenue	365,851	400,835
Operating expenses:		
Utilities -		
Fuel, purchased power and cost of gas sold	157,183	210,511
Operations and maintenance	64,760	67,409
Non-regulated energy operations and maintenance	22,595	23,474
Depreciation, depletion and amortization	38,559	31,910
Taxes - property, production and severance	11,510	8,198
Other operating expenses	1,196	966
Total operating expenses	295,803	342,468
Operating income	70,048	58,367
Other income (expense):		
Interest charges -		
Interest expense incurred (including amortization of debt issuance costs, premium, discount and realized settlements on interest rate swaps)	(29,914)	(29,203)
Allowance for funds used during construction - borrowed	518	3,363
Capitalized interest	161	2,434
Unrealized gain (loss) on interest rate swaps, net	12,045	5,465
Interest income	437	548
Allowance for funds used during construction - equity	277	295
Other income, net	1,472	731
Total other income (expense)	(15,004)	(16,367)
Income (loss) before equity in earnings (loss) of unconsolidated subsidiaries and income taxes	55,044	42,000
Equity in earnings (loss) of unconsolidated subsidiaries	(56)	993
Income tax benefit (expense)	(19,717)	(13,925)
Income (loss) from continuing operations	35,271	29,068
Income (loss) from discontinued operations, net of tax	(5,484)	(2,158)
Net income available for common stock	29,787	26,910
Other comprehensive income (loss), net of tax	(166)	(1,579)
Comprehensive income (loss)	$29,621	$25,331

Income (loss) per share, Basic -		
Income (loss) from continuing operations, per share	$0.81	$0.74
Income (loss) from discontinued operations, per share	(0.13)	(0.05)
Total income (loss) per share, Basic	$0.68	$0.69
Income (loss) per share, Diluted -		
Income (loss) from continuing operations, per share	$0.80	$0.73
Income (loss) from discontinued operations, per share	(0.12)	(0.05)
Total income (loss) per share, Diluted	$0.68	$0.68
Weighted average common shares outstanding:		
Basic	43,731	39,059
Diluted	43,969	39,761
Dividends paid per share of common stock	$0.37	$0.365

The accompanying Notes to Condensed Consolidated Financial Statements are an integral part of these Condensed Consolidated Financial Statements.

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BLACK HILLS CORPORATION
CONDENSED CONSOLIDATED BALANCE SHEETS
(unaudited)

	March 31, 2012	December 31, 2011	March 31, 2011
	(in thousands)		
ASSETS			
Current assets:			
Cash and cash equivalents	$56,132	$21,628	$26,418
Restricted cash	8,960	9,254	3,406
Accounts receivable, net	143,987	156,774	151,524
Materials, supplies and fuel	63,236	84,064	45,635
Derivative assets, current	17,877	18,583	7,812
Income tax receivable, net	10,399	9,344	20,173
Deferred income tax assets, net, current	23,710	37,202	20,491
Regulatory assets, current	56,282	59,955	36,834
Other current assets	26,546	21,266	17,486
Assets of discontinued operations	—	340,851	295,724
Total current assets	407,129	758,921	625,503
Investments	16,451	17,261	17,088
Property, plant and equipment	3,800,011	3,724,016	3,454,179
Less accumulated depreciation and depletion	(980,944)	(934,441)	(886,401)
Total property, plant and equipment, net	2,819,067	2,789,575	2,567,778
Other assets:			
Goodwill	353,396	353,396	353,396
Intangible assets, net	3,787	3,843	4,011
Derivative assets, non-current	881	1,971	1,184
Regulatory assets, non-current	186,093	182,175	140,735
Other assets, non-current	21,132	19,941	19,655
Total other assets	565,289	561,326	518,981
TOTAL ASSETS	$3,807,936	$4,127,083	$3,729,350

The accompanying Notes to Condensed Consolidated Financial Statements are an integral part of these Condensed Consolidated Financial Statements.

BLACK HILLS CORPORATION
CONDENSED CONSOLIDATED BALANCE SHEETS
(Continued)
(unaudited)

	March 31, 2012	December 31, 2011	March 31, 2011
	(in thousands, except share amounts)		
LIABILITIES AND STOCKHOLDERS' EQUITY			
Current liabilities:			
Accounts payable	$59,793	$104,748	$104,742
Accrued liabilities	151,130	151,319	127,235
Derivative liabilities, current	76,389	84,367	59,972
Regulatory liabilities, current	35,414	16,231	15,004
Notes payable	225,000	345,000	287,000
Current maturities of long-term debt	8,977	2,473	4,254
Liabilities of discontinued operations	—	173,929	163,293
Total current liabilities	556,703	878,067	761,500
Long-term debt, net of current maturities	1,272,016	1,280,409	1,184,830
Deferred credits and other liabilities:			
Deferred income tax liabilities, net, non-current	317,369	300,988	301,097
Derivative liabilities, non-current	43,169	49,033	15,790
Regulatory liabilities, non-current	112,516	108,217	90,923
Benefit plan liabilities	157,623	177,480	128,170
Other deferred credits and other liabilities	123,848	123,553	133,893
Total deferred credits and other liabilities	754,525	759,271	669,873
Stockholders' equity:			
Common stockholders' —			
Common stock $1 par value: 100,000,000 shares authorized: issued 44,151,428; 43,957,502 and 39,434,304 shares, respectively	44,151	43,958	39,434
Additional paid-in capital	725,512	722,623	601,021
Retained earnings	490,114	476,603	498,614
Treasury stock at cost – 65,015; 32,766 and 26,075 shares, respectively	(2,041)	(970)	(762)
Accumulated other comprehensive income (loss)	(33,044)	(32,878)	(25,160)
Total stockholders' equity	1,224,692	1,209,336	1,113,147
TOTAL LIABILITIES AND STOCKHOLDERS' EQUITY	$3,807,936	$4,127,083	$3,729,350

The accompanying Notes to Condensed Consolidated Financial Statements are an integral part of these Condensed Consolidated Financial Statements.

BLACK HILLS CORPORATION
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
(unaudited)

	Three Months Ended March 31,	
	2012	2011
Operating activities:	(in thousands)	
Net income (loss)	$29,787	$26,910
(Income) loss from discontinued operations, net of tax	5,484	2,158
Income (loss) from continuing operations	35,271	29,068
Adjustments to reconcile income (loss) from continuing operations to net cash provided by operating activities:		
Depreciation, depletion and amortization	38,559	31,910
Deferred financing cost amortization	2,719	1,528
Derivative fair value adjustments	1,594	2,010
Stock compensation	1,817	2,289
Unrealized mark-to-market (gain) loss on interest rate swaps	(12,045)	(5,465)
Deferred income taxes	18,083	25,844
Equity in (earnings) loss of unconsolidated subsidiaries	56	(993)
Allowance for funds used during construction - equity	(277)	(295)
Employee benefit plans	5,246	3,642
Other adjustments, net	2,187	(3,440)
Changes in certain operating assets and liabilities:		
Materials, supplies and fuel	20,828	17,280
Accounts receivable and other current assets	9,439	(5,591)
Accounts payable and other current liabilities	(42,368)	(44,617)
Regulatory assets	(776)	33,966
Regulatory liabilities	18,938	9,984
Contributions to defined benefit pension plans	(25,000)	—
Other operating activities, net	610	5,301
Net cash provided by operating activities of continuing operations	74,881	102,421
Net cash provided by (used in) operating activities of discontinued operations	21,184	8,850
Net cash provided by operating activities	96,065	111,271
Investing activities:		
Property, plant and equipment additions	(67,652)	(121,615)
Other investing activities	1,105	786
Net cash provided by (used in) investing activities of continuing operations	(66,547)	(120,829)
Proceeds from sale of business operations	108,837	—
Net cash provided by (used in) investing activities of discontinued operations	(824)	(929)
Net cash provided by (used in) investing activities	41,466	(121,758)
Financing activities:		
Dividends paid on common stock	(16,276)	(14,371)
Common stock issued	764	605
Short-term borrowings - issuances	56,453	210,000
Short-term borrowings - repayments	(176,453)	(172,000)
Long-term debt - repayments	(1,897)	(2,155)
Other financing activities	(2,758)	(14)

Net cash provided by (used in) financing activities of continuing operations	(140,167)	22,065
Net cash provided by (used in) financing activities of discontinued operations	—	—
Net cash provided by (used in) financing activities	(140,167)	22,065
Net change in cash and cash equivalents	(2,636)	11,578
Cash and cash equivalents, beginning of period*	58,768	32,438
Cash and cash equivalents, end of period*	$56,132	$44,016

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* Cash and cash equivalents include cash of discontinued operations of $37.1 million, $17.6 million and $16.0 million at December 31, 2011, March 31, 2011 and December 31, 2010, respectively.

See Note 3 for supplemental disclosure of cash flow information.

The accompanying Notes to Condensed Consolidated Financial Statements are an integral part of these Condensed Consolidated Financial Statements.

BLACK HILLS CORPORATION

Notes to Condensed Consolidated Financial Statements
(unaudited)
(Reference is made to Notes to Consolidated Financial Statements
included in the Company's 2011 Annual Report on Form 10-K)

(1) MANAGEMENT'S STATEMENT

The unaudited Condensed Consolidated Financial Statements included herein have been prepared by Black Hills Corporation together with our subsidiaries (the "Company," "us," "we," or "our"), pursuant to the rules and regulations of the SEC. Certain information and footnote disclosures normally included in financial statements prepared in accordance with accounting principles generally accepted in the United States of America have been condensed or omitted pursuant to such rules and regulations; however, we believe that the footnotes adequately disclose the information presented. These Condensed Consolidated Financial Statements should be read in conjunction with the consolidated financial statements and the notes thereto included in our 2011 Annual Report on Form 10-K filed with the SEC.

Accounting methods historically employed require certain estimates as of interim dates. The information furnished in the accompanying Condensed Consolidated Financial Statements reflects all adjustments, including accruals, which are, in the opinion of management, necessary for a fair presentation of the March 31, 2012, December 31, 2011 and March 31, 2011 financial information and are of a normal recurring nature. Certain industries in which we operate are highly seasonal and revenue from, and certain expenses for, such operations may fluctuate significantly among quarterly periods. Demand for electricity and natural gas is sensitive to seasonal cooling, heating and industrial load requirements, as well as changes in market price. In particular, the normal peak usage season for gas utilities is November through March and significant earnings variances can be expected between the Gas Utilities segment's peak and off-peak seasons. Due to this seasonal nature, our results of operations for the three months ended March 31, 2012 and March 31, 2011, and our financial condition as of March 31, 2012, December 31, 2011, and March 31, 2011 are not necessarily indicative of the results of operations and financial condition to be expected as of or for any other period. All earnings per share amounts discussed refer to diluted earnings per share unless otherwise noted.

On February 29, 2012, we sold our Energy Marketing segment, which resulted in this segment being classified as discontinued operations. For comparative purposes, all prior periods presented have been restated to reflect the classification of this segment as discontinued operations. For further information see Note 17.

Certain prior year data presented in the financial statements have been reclassified to conform to the current year presentation. Specifically, the Company has reclassified deferred financing cost amortization into a separate line on the Condensed Consolidated Statements of Cash Flow. This reclassification had no effect on total assets, net income, cash flows or earnings per share.

(2) RECENTLY ADOPTED AND RECENTLY ISSUED ACCOUNTING STANDARDS AND LEGISLATION

Recently Adopted Accounting Standards and Legislation

Other Comprehensive Income: Presentation of Comprehensive Income, ASU 2011-05 and ASU 2011-12

FASB issued an accounting standards update amending ASC 220, Comprehensive Income, to improve the comparability, consistency and transparency of reporting of comprehensive income. It amends existing guidance by allowing only two options for presenting the components of net income and other comprehensive income: (1) in a single continuous financial statement, statement of comprehensive income or (2) in two separate but consecutive financial statements, consisting of an income statement followed by a separate statement of other comprehensive income. Also, items that are reclassified from other comprehensive income to net income must be presented on the face of the financial statements. ASU 2011-05 requires retrospective application, and it is effective for the fiscal years, and interim periods within those years beginning after December 15, 2011. In December 2011, FASB issued ASU 2011-12 which indefinitely deferred the provisions of ASU 2011-05 requiring the presentation of reclassification adjustments on the face of the financial statements for items reclassified from other comprehensive income to net income.

At December 31, 2011, we elected to early adopt the provisions of ASU 2011-05 as amended by ASU 2011-12. The adoption changed our presentation of certain financial statements and provided additional details in the notes to the financial statements, but did not have any other impact on our financial statements.

Fair Value Measurement: Amendments to Achieve Common Fair Value Measurement and Disclosure Requirements, ASU 2011-04

FASB issued an accounting standards update amending ASC 820, Fair Value Measurements and Disclosures, to achieve common fair value measurement and disclosure requirements between GAAP and IFRS. Additional disclosure requirements in the update include: (1) for Level 3 fair value measurements - quantitative information about unobservable inputs used, a description of the valuation processes used by the entity, and a qualitative discussion about the sensitivity of the measurements to changes in the unobservable inputs; (2) for an entity's use of a non-financial asset that is different from the asset's highest and best use - the reason for the difference; (3) for financial instruments not measured at fair value but for which disclosure of fair value is required - the fair value hierarchy level in which the fair value measurements were determined; and (4) the disclosure of all transfers between Level 1 and Level 2 of the fair value hierarchy. ASU 2011-04 is effective for fiscal years, and interim periods within those years, beginning after December 31, 2011. The amendment required additional details in notes to financial statements, but did not have any other impact on our financial statements. Additional disclosures are included in Notes 14 and 15.

Intangibles - Goodwill and Other: Testing Goodwill for Impairment, ASU 2011-08

In September 2011, the FASB issued an amendment to ASC 350, Intangibles - Goodwill and Other, to provide an option to perform a qualitative assessment to determine whether further impairment testing of goodwill is necessary. Specifically, an entity has the option to first assess qualitative factors to determine whether it is necessary to perform the current two-step test. If an entity believes, as a result of its qualitative assessment, that it is more-likely-than-not that the fair value of a reporting unit is less than its carrying amount, the quantitative impairment test is required. Otherwise, no further testing is required. This standard is effective for annual and interim goodwill impairment testing performed for fiscal years beginning after December 15, 2011. We perform our annual impairment testing in November of each year. The adoption of this standard will not have an impact on our financial statements.

Recently Issued Accounting Standards and Legislation

Balance Sheet: Disclosure about Offsetting Assets and Liabilities, ASU 2011-11
In December 2011, the FASB issued revised accounting guidance to amend ASC 210, Balance Sheet, related to the existing disclosure requirements for offsetting financial assets and liabilities to enhance current disclosures, as well as to improve comparability of balance sheets prepared under GAAP and IFRS. The revised disclosure guidance affects all companies that have financial instruments and derivative instruments that are either offset in the balance sheet (i.e., presented on a net basis) or subject to an enforceable master netting and/or similar arrangement. In addition, the revised guidance requires that certain enhanced quantitative and qualitative disclosures are made with respect to a company's netting arrangements and/or rights of offset associated with its financial instruments and/or derivative instruments. The revised disclosure guidance is effective on a retrospective basis for interim and annual periods beginning January 1, 2013. Management does not believe that the adoption of this standard will have an impact on the Company’s financial position, results of operations or cash flows.

(3) SUPPLEMENTAL DISCLOSURE OF CASH FLOW INFORMATION

Three Months Ended

	March 31, 2012 (in thousands)	March 31, 2011
Non-cash investing activities from continuing operations—		
Property, plant and equipment acquired with accrued liabilities	$31,644	$32,220
Capitalized assets associated with retirement obligations	$2,826	$—
Cash (paid) refunded during the period for continuing operations—		
Interest (net of amounts capitalized)	$(16,799)	$(11,572)
Income taxes, net	$(1,838)	$48

(4) MATERIALS, SUPPLIES AND FUEL

The amounts of Materials, supplies and fuel included in the accompanying Condensed Consolidated Balance Sheets, by major classification, were as follows (in thousands) as of:

	March 31, 2012	December 31, 2011	March 31, 2011
Materials and supplies	$44,361	$40,838	$34,129
Fuel - Electric Utilities	7,812	8,201	9,307
Natural gas in storage - gas utilities	11,063	35,025	2,199
Total materials, supplies and fuel	$63,236	$84,064	$45,635

(5) ACCOUNTS RECEIVABLE AND ALLOWANCE FOR DOUBTFUL ACCOUNTS

Accounts receivable consists primarily of customer trade accounts. The Gas Utilities balance fluctuates primarily due to seasonality. We maintain an allowance for doubtful accounts that reflects our best estimate of probable uncollectible trade receivables. We regularly review our trade receivable allowances by considering such factors as historical experience, credit worthiness, the age of the receivable balances and current economic conditions that may affect our ability to collect.

Following is a summary of receivables (in thousands) as of:

March 31, 2012	Accounts Receivable, Trade	Unbilled Revenue	Less Allowance for Doubtful Accounts	Accounts Receivable, net
Electric	$44,356	$19,381	$(585)	$63,152
Gas	44,287	18,502	(936)	61,853
Oil and Gas	15,014	—	(105)	14,909
Coal Mining	2,578	—	—	2,578
Power Generation	265	—	—	265
Corporate	1,230	—	—	1,230
Total	$107,730	$37,883	$(1,626)	$143,987

December 31, 2011	Accounts Receivable, Trade	Unbilled Revenue	Less Allowance for Doubtful Accounts	Accounts Receivable, net
Electric	$42,773	$21,151	$(545)	$63,379
Gas	39,353	38,992	(1,011)	77,334
Oil and Gas	11,282	—	(105)	11,177
Coal Mining	4,056	—	—	4,056
Power Generation	282	—	—	282
Corporate	546	—	—	546
Total	$98,292	$60,143	$(1,661)	$156,774

March 31, 2011	Accounts Receivable, Trade	Unbilled Revenue	Less Allowance for Doubtful Accounts	Accounts Receivable, net
Electric	$46,077	$16,196	$(728)	$61,545
Gas	58,665	21,620	(1,763)	78,522
Oil and Gas	7,503	—	(161)	7,342
Coal Mining	982	—	—	982
Power Generation	2,050	—	—	2,050
Corporate	1,083	—	—	1,083
Total	$116,360	$37,816	$(2,652)	$151,524

(6) NOTES PAYABLE

Our credit facility and debt securities contain certain restrictive financial covenants. As of March 31, 2012, we were in compliance with all of these covenants.

We had the following short-term debt outstanding as of the Condensed Consolidated Balance Sheet dates (in thousands):

	March 31, 2012		December 31, 2011		March 31, 2011	
	Balance Outstanding	Letters of Credit	Balance Outstanding	Letters of Credit	Balance Outstanding	Letters of Credit
Revolving Credit Facility	$75,000	$41,200	$195,000	$43,700	$187,000	$51,000
Term Loan due 2011*	—	—	—	—	100,000	—
Term Loan due 2012	150,000	—	150,000	—	—	—
Total	$225,000	$41,200	$345,000	$43,700	$287,000	$51,000

* The short-term loan was renegotiated to a longer term note, maturing in 2013.

Revolving Credit Facility

On February 1, 2012, we entered into a new $500 million Revolving Credit Facility expiring February 1, 2017 which contains an accordion feature allowing us, with the consent of the administrative agent, to increase the capacity of the facility to $750 million. The Revolving Credit Facility can be used for the issuance of letters of credit, to fund working capital needs and for other corporate purposes. Borrowings are available under a base rate option or a Eurodollar option. The cost of borrowings or letters of credit is determined based upon our credit ratings. At current credit ratings levels, the margins for base rate borrowings, Eurodollar borrowings and letters of credit were 0.50%, 1.50% and 1.50%, respectively, at March 31, 2012. The facility contains a commitment fee that is to be charged on the unused amount of the Revolving Credit Facility. Based upon current credit ratings, the fee is 0.25%.

Deferred financing costs on the new facility of $2.8 million are being amortized over the estimated useful life of the Revolving Credit Facility and are included in Interest expense on the accompanying Condensed Consolidated Statements of Income and Comprehensive Income. Upon entering into the new facility, $1.5 million of deferred financing costs relating to the previous credit facility were written off through Interest expense.

Debt Covenants

Certain debt obligations require compliance with the following covenants at the end of each quarter (dollars in thousands).

	As of	Covenant

	March 31, 2012	Requirement
Consolidated Net Worth	$1,224,692	$899,024
Recourse Leverage Ratio	56.4 %	65.0 %

(7) LONG TERM DEBT

Pollution Control Revenue Bonds

On March 28, 2012, Black Hills Power provided notice to the trustee of its intent to call the Pollution Control Refund Revenue Bonds which were originally due to mature on October 1, 2014. The principal amount due on the bonds has been reclassified to Current maturities of long-term debt on the accompanying Condensed Consolidated Balance Sheets. Repayment of $6.5 million principal and accrued interest will be made on May 15, 2012.

(8) EARNINGS PER SHARE

Basic earnings (loss) per share from continuing operations is computed by dividing Income (loss) from continuing operations by the weighted-average number of common shares outstanding during the period. Diluted earnings (loss) per share is computed by including all dilutive common shares potentially outstanding during a period. A reconciliation of share amounts used to compute earnings (loss) per share is as follows (in thousands):

	Three Months Ended March 31,	
	2012	2011
Income (loss) from continuing operations	$35,271	$29,068
Weighted average shares - basic	43,731	39,059
Dilutive effect of:		
Restricted stock	147	132
Stock options	18	17
Equity forward instruments	—	460
Other dilutive effects	73	93
Weighted average shares - diluted	43,969	39,761

The following outstanding securities were not included in the computation of diluted earnings per share as their effect would have been anti-dilutive (in thousands):

	Three Months Ended March 31,	
	2012	2011
Stock options	127	83
Restricted stock	31	7
Other stock	16	—
Anti-dilutive shares	174	90

(9) COMPREHENSIVE INCOME (LOSS)

The following table presents the components of our comprehensive income (loss) (in thousands):

Three Months Ended March 31, 2012	Pre-tax Amount	Tax (Expense) Benefit	Net-of-tax Amount
Fair value adjustment of derivatives designated as cash flow hedges	$521	$55	$576

Reclassification adjustments of cash flow hedges settled and included in net income (loss)	(1,187)	445	(742)
Other comprehensive income (loss)	$(666)	$500	$(166)

Three Months Ended March 31, 2011	Pre-tax Amount	Tax (Expense) Benefit	Net-of-tax Amount
Fair value adjustment of derivatives designated as cash flow hedges	$(3,785)	$1,637	$(2,148)
Reclassification adjustments of cash flow hedges settled and included in net income (loss)	861	(292)	569
Other comprehensive income (loss)	$(2,924)	$1,345	$(1,579)

Balances by classification included within Accumulated other comprehensive income (loss) on the accompanying Condensed Consolidated Balance Sheets are as follows (in thousands):

	Derivatives Designated as Cash Flow Hedges	Employee Benefit Plans	Total
Balance as of December 31, 2011	$(13,802)	$(19,076)	$(32,878)
Other comprehensive income (loss)	(166)	—	(166)
Ending Balance March 31, 2012	$(13,968)	$(19,076)	$(33,044)

	Derivatives Designated as Cash Flow Hedges	Employee Benefit Plans	Total
Balance as of December 31, 2010	$(12,439)	$(11,142)	$(23,581)
Other comprehensive income (loss)	(1,579)	—	(1,579)
Ending Balance March 31, 2011	$(14,018)	$(11,142)	$(25,160)

(10) COMMON STOCK

Other than the following transactions, we had no material changes in our common stock during the three months ended March 31, 2012 from the amount reported in Note 11 of the Notes to Consolidated Financial Statements in our 2011 Annual Report on Form 10-K.

Equity Compensation Plans

- We granted 66,690 target performance shares to certain officers and business unit leaders for the January 1, 2012 through December 31, 2014 performance period during the three months ended March 31, 2012. Actual shares are issued after the end of the performance plan period. Performance shares are awarded based on our total stockholder return over the designated performance period as measured against a selected peer group and can range from 0% to 200% of target. In addition, certain stock price performance must be achieved for a payout to occur. The final value of the performance shares will vary according to the number of shares of common stock that are ultimately granted based upon the actual level of attainment of the performance criteria. The performance awards are paid 50% in the form of cash and 50% in shares of common stock. The grant date fair value was $32.26 per share.

- We granted 139,550 shares of restricted common stock and restricted stock units during the three months ended March 31, 2012. The pre-tax compensation cost related to the awards of restricted stock and restricted stock units of approximately $4.9 million will be recognized over the vesting period.

- Stock options totaling 41,206 shares were exercised during the three months ended March 31, 2012 at a weighted-average exercise price of $28.28 per share, providing $1.2 million of proceeds.

- We issued 3,690 shares of common stock under our short-term incentive compensation plan during the three months ended March 31, 2012. Pre-tax compensation cost related to the awards was approximately $0.1 million, which was expensed in 2011.

Stock-based compensation expense for the three months ended March 31, 2012 and 2011 was $1.8 million and $2.3 million, respectively.

As of March 31, 2012, total unrecognized compensation expense related to non-vested stock awards was $12.2 million and is expected to be recognized over a weighted-average period of 2.3 years.

Dividend Reinvestment and Stock Purchase Plan

We have a DRIP under which stockholders may purchase additional shares of common stock through dividend reinvestment and/or optional cash payments at 100% of the recent average market price. We have the option of issuing new shares or purchasing the shares on the open market. We are issuing new shares. We issued 27,155 new shares at a weighted-average price of $33.20 during the three months ended March 31, 2012. Unissued common stock totaling 426,109 shares was available for future offering under the DRIP at March 31, 2012.

Dividend Restrictions

Our Revolving Credit Facility and other debt obligations contain restrictions on the payment of cash dividends upon a default or event of default. As of March 31, 2012, we were in compliance with these covenants.

Due to our holding company structure, substantially all of our operating cash flows are provided by dividends paid or distributions made by our subsidiaries. The cash to pay dividends to our stockholders is derived from these cash flows. As a result, certain statutory limitations or regulatory or financing agreements could affect the levels of distributions allowed to be made by our subsidiaries. The following restrictions on distributions from our subsidiaries existed at March 31, 2012:

- Our utilities are generally limited to the amount of dividends allowed to be paid to us as a utility holding company under the Federal Power Act and settlement agreements with state regulatory jurisdictions. As of March 31, 2012, the restricted net assets at our Utilities Group were approximately $81.4 million.

- As required by the covenant in the Black Hills Wyoming project financing, Black Hills Non-regulated Holdings has maintained restricted equity of at least $100.0 million.

(11) EMPLOYEE BENEFIT PLANS

Defined Benefit Pension Plans

We have three non-contributory defined benefit pension plans (the "Pension Plans"). One covers certain eligible employees of the following subsidiaries: Black Hills Service Company, Black Hills Power, WRDC and BHEP, one covers certain eligible employees of Cheyenne Light, and one covers certain eligible employees of Black Hills Energy. The Pension Plan benefits are based on years of service and compensation levels.

The components of net periodic benefit cost for the Pension Plans were as follows (in thousands):

	Three Months Ended March 31,	
	2012	2011
Service cost	$1,430	$1,355
Interest cost	3,687	3,732
Expected return on plan assets	(4,084)	(4,239)

Prior service cost	22	25
Net loss (gain)	2,408	1,135
Net periodic benefit cost	$3,463	$2,008

Non-pension Defined Benefit Postretirement Healthcare Plans

We sponsor the following retiree healthcare plans (the "Healthcare Plans"): the Black Hills Corporation Postretirement Healthcare Plan, the Healthcare Plan for Retirees of Cheyenne Light, and the Black Hills Energy Postretirement Healthcare Plan. Employees who participate in the Healthcare Plans and who retire on or after meeting certain eligibility requirements are entitled to postretirement healthcare benefits.

The components of net periodic benefit cost for the Healthcare Plans were as follows (in thousands):

	Three Months Ended March 31,	
	2012	2011
Service cost	$402	$375
Interest cost	523	542
Expected return on plan assets	(19)	(41)
Prior service cost (benefit)	(125)	(120)
Net loss (gain)	222	169
Net periodic benefit cost	$1,003	$925

Supplemental Non-qualified Defined Benefit Plans

We have various supplemental retirement plans for key executives (the "Supplemental Plans"). The Supplemental Plans are non-qualified defined benefit plans.

The components of net periodic benefit cost for the Supplemental Plans were as follows (in thousands):

	Three Months Ended March 31,	
	2012	2011
Service cost	$246	$257
Interest cost	331	324
Prior service cost	1	1
Net loss (gain)	202	127
Net periodic benefit cost	$780	$709

Contributions

We anticipate that we will make contributions to the benefit plans during 2012 and 2013. Contributions to the Defined Benefit Plans will be made in cash and contributions to the Healthcare Plans and the Supplemental Plans are expected to be made in the form of benefit payments. Contributions are as follows (in thousands):

	Contributions Made Three Months Ended March 31, 2012	Additional Contributions Anticipated for 2012	Contributions Anticipated for 2013
Defined Benefit Pension Plans	$25,000	$—	$4,500
Non-pension Defined Benefit Postretirement Healthcare Plans	$1,063	$3,188	$4,380
Supplemental Non-qualified Defined Benefit Plans	$278	$833	$1,090

(12) BUSINESS SEGMENTS INFORMATION

Our reportable segments are based on our method of internal reporting, which generally segregates the strategic business groups due to differences in products, services and regulation. All of our operations and assets are located within the United States.

On February 29, 2012, we sold our Energy Marketing segment, Enserco, which resulted in this segment being classified as discontinued operations. For comparative purposes, all prior periods presented have been restated to reflect the classification of this segment as discontinued operations. Indirect corporate costs and inter-segment interest expense related to Enserco that have not been classified as discontinued operations reclassified to our Corporate segment. For further information see Note 17.

We conduct our operations through the following five reportable segments:

Utilities Group —

- Electric Utilities, which supplies electric utility service to areas in South Dakota, Wyoming, Colorado and Montana and natural gas utility service to Cheyenne, Wyoming and vicinity; and

- Gas Utilities, which supplies natural gas utility service to areas in Colorado, Iowa, Kansas and Nebraska.

Non-regulated Energy Group —

- Oil and Gas, which acquires, explores for, develops and produces crude oil and natural gas interests located in the Rocky Mountain region and other states;

- Power Generation, which produces and sells power and capacity to wholesale customers from power plants located in Wyoming and Colorado; and

- Coal Mining, which engages in the mining and sale of coal from our mine near Gillette, Wyoming.

Segment information follows the accounting policies described in Note 1 of the Notes to Consolidated Financial Statements in our 2011 Annual Report on Form 10-K.

Segment information included in the accompanying Condensed Consolidated Statements of Income and Comprehensive Income and Condensed Consolidated Balance Sheets was as follows (in thousands):

Three Months Ended March 31, 2012	External Operating Revenues	Intercompany Operating Revenues	Income (Loss) from Continuing Operations
Utilities:			
Electric	$156,133	$3,036	$8,746
Gas	180,522	—	15,207
Non-regulated Energy:			
Oil and Gas	21,645	—	13
Power Generation	1,178	18,449	6,914
Coal Mining	6,373	8,616	1,000
Corporate [(a)(b)]	—	—	3,391
Intercompany eliminations	—	(30,101)	—
Total	$365,851	$—	$35,271

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Three Months Ended March 31, 2011	External Operating Revenues	Intercompany Operating Revenues	Income (Loss) from Continuing Operations
Utilities:			
Electric	$144,430	$3,839	$10,249
Gas	230,266	—	19,263
Non-regulated Energy:			
Oil and Gas	17,906	—	(715)
Power Generation	687	6,933	1,186
Coal Mining	7,614	7,881	(1,298)
Corporate [a][b]	—	—	451
Intercompany eliminations	—	(18,721)	(68)
Total	$400,903	$(68)	$29,068

(a) Income (loss) from continuing operations includes $7.8 million and $3.6 million net after-tax mark-to-market gain on interest rate swaps for the three months ended March 31, 2012 and March 31, 2011, respectively.

(b) Certain direct corporate costs and inter-segment interest expense previously allocated to our Energy Marketing segment were not classified as discontinued operations but were included in the Corporate segment. See Note 17 for further information.

Total Assets (net of inter-company eliminations)	March 31, 2012	December 31, 2011	March 31, 2011
Utilities:			
Electric [a]	$2,268,524	$2,254,914	$1,868,600
Gas	717,185	746,444	683,927
Non-regulated Energy:			
Oil and Gas	430,851	425,970	355,357
Power Generation [a]	128,225	129,121	336,827
Coal Mining	87,139	88,704	94,416
Corporate [b]	176,012	141,079	94,499
Discontinued operations [c]	—	340,851	295,724
Total assets	$3,807,936	$4,127,083	$3,729,350

(a) The PPA under which the new generating facility was constructed at our Pueblo Airport Generation site by Colorado IPP to support Colorado Electric customers is accounted for as a capital lease. Therefore, commencing December 31, 2011, assets previously at Power Generation are now accounted for at Colorado Electric under accounting for a capital lease.

(b) Assets of the Corporate segment were restated due to deferred taxes that were not classified as discontinued operations.

(c) See Note 17 for further information relating to discontinued operations.

(13) RISK MANAGEMENT ACTIVITIES

Our activities in the regulated and non-regulated energy sectors expose us to a number of risks in the normal operation of our businesses. Depending on the activity, we are exposed to varying degrees of market risk and credit risk. To manage and mitigate these identified risks, we have adopted the Black Hills Corporation Risk Policies and Procedures as discussed in our 2011 Annual Report on Form 10-K filed with the SEC.

Market Risk

Market risk is the potential loss that might occur as a result of an adverse change in market price or rate. We are exposed to the following market risks:

- Commodity price risk associated with our natural long position with crude oil and natural gas reserves and production, fuel procurement for certain of our gas-fired generation assets and variability in revenue due to changes in gas usage at our regulated segment; and

- Interest rate risk associated with our variable rate credit facility, project financing floating rate debt and our derivative instruments.

Our exposure to these market risks is affected by a number of factors including the size, duration, and composition of our energy portfolio, the absolute and relative levels of interest rates and commodity prices, the volatility of these prices and rates, and the liquidity of the related interest rate and commodity markets.

Credit Risk

Credit risk is the risk of financial loss resulting from non-performance of contractual obligations by a counterparty.

For production and generation activities, we attempt to mitigate our credit exposure by conducting business primarily with investment grade companies and credit quality municipalities and electric cooperatives, setting tenor and credit limits commensurate with counterparty financial strength, obtaining master netting agreements, and mitigating credit exposure with less creditworthy counterparties through parental guarantees, prepayments, letters of credit, and other security agreements.

We perform ongoing credit evaluations of our customers and adjust credit limits based upon payment history and the customer's current creditworthiness, as determined by review of their current credit information. We maintain a provision for estimated credit losses based upon historical experience and any specific customer collection issue that is identified.

As of March 31, 2012, our credit exposure (exclusive of retail customers of the regulated utilities) was concentrated primarily among investment grade companies. Credit exposure with non-investment grade or non-rated counterparties, was supported partially through letters of credit, prepayments or parental guarantees.

We actively manage our exposure to certain market and credit risks as described in Note 3 of the Notes to the Consolidated Financial Statements in our 2011 Annual Report on Form 10-K. Our derivative and hedging activities included in the accompanying Condensed Consolidated Balance Sheets and Condensed Consolidated Statements of Income and Comprehensive Income are detailed below and within Note 14.

Oil and Gas Exploration and Production

We produce natural gas and crude oil through our exploration and production activities. Our natural "long" positions, or unhedged open positions, result in commodity price risk and variability to our cash flows.

We hold a portfolio of swaps and options to hedge portions of our crude oil and natural gas production. We elect hedge accounting on those OTC swaps and options. These transactions were designated at inception as cash flow hedges, documented under accounting for derivatives and hedging, and initially met prospective effectiveness testing. Effectiveness of our hedging position is evaluated at least quarterly.

The derivatives were marked to fair value and are recorded as Derivative assets or Derivative liabilities on the accompanying Condensed Consolidated Balance Sheets. The effective portion of the gain or loss on these derivatives is reported in Accumulated other comprehensive income (loss) and the ineffective portion, if any, is reported in Revenue.

We had the following derivatives and related balances (dollars in thousands) as of:

	March 31, 2012		December 31, 2011		March 31, 2011	
	Crude Oil Swaps/ Options	Natural Gas Swaps	Crude Oil Swaps/ Options	Natural Gas Swaps	Crude Oil Swaps/ Options	Natural Gas Swaps
Notional [(a)]	522,000	5,001,750	528,000	5,406,250	487,500	5,974,800
Maximum terms in years [(b)]	1.25	1.50	1.25	1.75	1.00	0.25
Derivative assets, current	$406	$8,256	$729	$8,010	$108	$6,649
Derivative assets, non-current	$46	$808	$771	$1,148	$—	$975
Derivative liabilities, current	$2,904	$—	$2,559	$—	$4,688	$—
Derivative liabilities, non-current	$1,084	$—	$811	$7	$2,678	$157
Pre-tax accumulated other comprehensive income (loss)	$(3,566)	$9,064	$(1,928)	$9,152	$(7,613)	$7,467
Revenue [(c)]	$30	$—	$58	$—	$355	$—

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(a) Crude oil in Bbls, gas in MMBtus

(b) Refers to the term of the derivative instrument. Assets and liabilities are classified as current or non-current based on the term of the hedged transaction and the corresponding settlement of the derivative instruments.

(c) Represents the amortization of put premiums.

Based on March 31, 2012 market prices, a $4.3 million gain would be reclassified from AOCI during the next 12 months. Estimated and actual realized gains will change during future periods as market prices fluctuate.

Utilities

Our utility customers are exposed to the effect of volatile natural gas prices; therefore, as allowed or required by state utility commissions, we have entered into certain exchange-traded natural gas futures, options and basis swaps to reduce our customers' underlying exposure to these fluctuations. These transactions are considered derivatives and in accordance with accounting standards for derivatives and hedging, mark-to-market adjustments are recorded as Derivative assets or Derivative liabilities on the accompanying Condensed Consolidated Balance Sheets. Gains and losses, as well as option premiums and commissions, on these transactions are recorded as Regulatory assets or Regulatory liabilities in accordance with accounting standards for regulated operations. Accordingly, the earnings impact is recognized in the Condensed Consolidated Statements of Income and Comprehensive Income when the related costs are recovered through our rates.

The contract or notional amounts and terms of the natural gas derivative commodity instruments held at our Utilities were as follows as of:

	March 31, 2012		December 31, 2011		March 31, 2011	
	Notional (MMBtus)	Latest Expiration (months)	Notional (MMBtus)	Latest Expiration (months)	Notional (MMBtus)	Latest Expiration (months)
Natural gas futures purchased	11,550,000	81	14,310,000	84	4,680,000	24
Natural gas options purchased	670,000	12	1,720,000	3	—	—
Natural gas basis swaps purchased	7,640,000	81	7,160,000	60	—	—

We had the following derivative balances related to the hedges in our Utilities (in thousands) as of:

	March 31, 2012	December 31, 2011	March 31, 2011
Derivative assets, current	$9,215	$ 9,844	$1,056
Derivative assets, non-current	$27	$ 52	$209
Derivative liabilities, non-current	$6,407	$ 7,156	$—
Net unrealized gain (loss) included in Regulatory assets or liabilities	$15,223	$ 17,556	$2,455
Included in Derivatives:			
Cash collateral receivable (payable)	$17,651	$ 19,416	$3,720
Option premiums and commissions	$407	$ 880	$—

Financing Activities

We have entered into floating-to-fixed interest rate swap agreements to reduce our exposure to interest rate fluctuations associated with our floating rate debt obligations. Our interest rate swaps and related balances were as follows (dollars in thousands) as of:

	March 31, 2012		December 31, 2011		March 31, 2011	
	Designated Interest Rate Swaps	De-designated Interest Rate Swaps*	Designated Interest Rate Swaps	De-designated Interest Rate Swaps*	Designated Interest Rate Swaps	De-designated Interest Rate Swaps*
Notional	$150,000	$ 250,000	$150,000	$ 250,000	$150,000	$ 250,000
Weighted average fixed interest rate	5.04 %	5.67 %	5.04 %	5.67 %	5.04 %	5.67 %
Maximum terms in years	4.75	1.75	5.00	2.00	5.75	0.75
Derivative liabilities, current	$6,777	$ 66,708	$6,513	$ 75,295	$6,769	$ 48,515
Derivative liabilities, non-current	$18,441	$ 17,237	$20,363	$ 20,696	$12,955	$ —
Pre-tax accumulated other comprehensive income (loss)	$(25,218)	$ —	$(26,876)	$ —	$(19,724)	$ —
Pre-tax gain (loss)	$—	$ 12,045	$—	$ (42,010)	$—	$ 5,465
Cash collateral receivable (payable)	$—	$ —	$—	$ —	$—	$ —

* Maximum terms in years reflect the amended early termination dates. If the early termination dates are not extended, the swaps will require cash settlement based on the swap value on the termination date. If extended, de-designated swaps totaling $100 million terminate in 7 years and de-designated swaps totaling $150 million terminate in 17 years.

$50 million of our de-designated swaps have collateral requirements based on our corporate credit ratings. At our current credit ratings, we would be required to post collateral for any amount by which the swaps' negative mark-to-market fair value exceeds $20 million. If our senior unsecured credit rating drops to BB+ or below by S&P, or Ba1 or below by Moody's, we would be required to post collateral for the entire amount of the swaps' negative mark-to-market fair value.

Based on March 31, 2012 market interest rates and balances related to our designated interest rate swaps, a loss of approximately $6.8 million would be reclassified from AOCI during the next 12 months. Estimated and realized losses will change during future periods as market interest rates change.

(14) FAIR VALUE MEASUREMENTS

Derivative Financial Instruments

Assets and liabilities carried at fair value are classified and disclosed in one of the following categories:

Level 1 — Unadjusted quoted prices available in active markets that are accessible at the measurement date for identical unrestricted assets or liabilities. This level primarily consists of financial instruments such as exchange-traded securities or listed derivatives.

Level 2 — Pricing inputs include quoted prices for identical or similar assets and liabilities in active markets, quoted prices for identical or similar assets or liabilities in markets that are not active, inputs other than quoted prices that are observable for the asset or liability and inputs that are derived principally from or corroborated by observable market data by correlation or other means.

Level 3 — Pricing inputs include significant inputs that are generally less observable from objective sources. These inputs reflect management's best estimate of fair value using its own assumptions about the assumptions a market participant would use in pricing the asset or liability.

Assets and liabilities are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. Our assessment of the significance of a particular input to the fair value measurement requires judgment and may affect the placement within the fair value hierarchy levels. We record transfers, if necessary, between levels at the end of the reporting period for all of our financial instruments.

Valuation Methodologies

Oil and Gas Segment:

- The commodity option contracts for the Oil and Gas segment are valued under the market approach and include calls and puts. Fair value was derived using quoted prices from third party brokers for similar instruments as to quantity and timing. The prices are then validated through multiple sources.

- The commodity basis swaps for the Oil and Gas segment are valued under the market approach using the instrument's current forward price strip hedged for the same quantity and date and discounted based on the three-month LIBOR.

Utilities Segment:

- The commodity contracts for the Utilities, valued using the market approach, include exchange-traded futures, options and basis swaps (Level 2) and OTC basis swaps (Level 3) for natural gas contracts. For Level 2 assets and liabilities, fair value was derived using broker quotes validated by the Chicago Mercantile Exchange pricing for similar instruments. For Level 3 assets and liabilities, fair value was derived using average price quotes from the OTC contract broker and an independent third party market participant.

Corporate Segment:

- The interest rate swaps are valued using the market valuation approach. The company establishes fair value by obtaining price quotes directly from the counterparty which are based on the floating three-month LIBOR curve for the term of the contract. The fair value obtained from the counterparty is then validated by utilizing a nationally recognized service that obtains observable inputs to compute fair value for the same instrument. In addition, the fair value for the interest rate swap derivatives includes a CVA component. The CVA considers the fair value of the interest rate swap and the probability of default based on the life of the contract. For the probability of a default component, we utilize observable inputs supporting Level 2 disclosure by using our credit default spread, if available, or a generic credit default spread curve that takes into account our credit ratings.

Recurring Fair Value Measurements

The following tables set forth by level within the fair value hierarchy our assets and liabilities that were accounted for at fair value on a recurring basis (in thousands):

	As of March 31, 2012					
	Level 1	Level 2	Level 3	Counterparty Netting	Cash Collateral	Total
Assets:						
Commodity derivatives — Oil and Gas						
Options -- Oil	$—	$404	$—	$—	$—	$404
Basis Swaps -- Oil	—	48	—	—	—	48
Options -- Gas	—	—	—	—	—	—
Basis Swaps -- Gas	—	9,064	—	—	—	9,064
Commodity derivatives — Utilities	—	(8,412)	3	—	17,651	9,242
Repurchase agreement [(a)]	43,128	—	—	—	—	43,128
Money market funds and term deposits [(a)]	12,791	—	—	—	—	12,791
Total	$55,919	$1,104	$3	$—	$17,651	$74,677
Liabilities:						
Commodity derivatives — Oil and Gas						
Options -- Oil	$—	$1,347	$—	$—	$—	$1,347
Basis Swaps -- Oil	—	2,641	—	—	—	2,641
Options -- Gas	—	—	—	—	—	—
Basis Swaps -- Gas	—	—	—	—	—	—
Commodity derivatives — Utilities	—	6,359	48	—	—	6,407
Interest rate swaps	—	109,163	—	—	—	109,163
Total	$—	$119,510	$48	$—	$—	$119,558

(a) Level 1 assets and liabilities and described at Note 15.

	As of December 31, 2011					
	Level 1	Level 2	Level 3	Counterparty Netting	Cash Collateral	Total
Assets:						
Commodity derivatives — Oil and Gas	$—	$9,885	$768	$5	$—	$10,658
Commodity derivatives —Utilities	—	(9,520)	—	—	19,416	9,896
Money market funds	6,005	—	—	—	—	6,005
Total	$6,005	$365	$768	$5	$19,416	$26,559
Liabilities:						
Commodity derivatives — Oil and Gas	$—	$2,207	$1,165	$5	$—	$3,377
Commodity derivatives — Utilities	—	7,156	—	—	—	7,156
Interest rate swaps	—	122,867	—	—	—	122,867
Total	$—	$132,230	$1,165	$5	$—	$133,400

	As of March 31, 2011					
	Level 1	Level 2	Level 3	Counterparty Netting	Cash Collateral	Total
Assets:						
Commodity derivatives — Oil and Gas	$—	$7,626	$106	$—	$—	$7,732
Commodity derivatives — Utilities	—	(2,455)	—	—	3,720	1,265
Money market funds	9,050	—	—	—	—	9,050
Total	$9,050	$5,171	$106	$—	$3,720	$18,047
Liabilities:						
Commodity derivatives — Oil and Gas	$—	$7,523	$—	$—	$—	$7,523
Commodity derivatives — Utilities	—	—	—	—	—	—
Interest rate swaps	—	68,239	—	—	—	68,239
Total	$—	$75,762	$—	$—	$—	$75,762

The following table presents the quantitative information about level 3 fair value measurements (dollars shown in thousands):

	Fair Value at March 31, 2012	Valuation Technique	Unobservable Input	Range (Weighted Average)
ASSETS				
Commodity derivatives - Utilities[(a)]	$3	Independent price quotes	Long-term natural gas prices	Not applicable
LIABILITIES				
Commodity derivatives - Utilities[(a)]	$48	Independent price quotes	Long-term natural gas prices	Not applicable

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(a) The significant unobservable inputs used in the fair value measurement of the long-term OTC contracts are based on the average of price quotes from an independent third party market participant and the OTC contract broker. Significant changes to these inputs along with the contract term would impact the derivative asset/liability and regulatory asset/liability, but will not impact the results of operations until the contract is settled under the original terms of the contract. The contracts will be classified as Level 2 once settlement is within 60 months of maturity and quoted market prices from a market exchange are available.

The following tables present the changes in Level 3 recurring fair value for the three months ended March 31, 2012 and 2011, respectively (in thousands):

	Three Months Ended March 31, 2012			
Assets:	Commodity Derivatives -- Oil	Commodity Derivatives -- Gas	Commodity Derivatives -- Utilities	Total
Balances as of beginning of period	$768	$—	$—	$768
Total gain (loss) included in revenue	—	—	—	—
Total gain (loss) included in AOCI	(360)	—	—	(360)
Purchases	—	—	3	3
Issuances	—	—	—	—
Settlements	(4)	—	—	(4)
Transfers into level 3 [(a)]	—	—	—	—
Transfers out of level 3[(b)(c)]	(404)	—	—	(404)
Balances at end of period	$—	$—	$3	$3

Changes in unrealized gains (losses) relating to instruments still held as of period-end	$—	$—	$3	$3

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Liabilities:	Three Months Ended March 31, 2012 Commodity Derivatives -- Oil	Commodity Derivatives -- Gas	Commodity Derivatives -- Utilities	Total
Balances as of beginning of period	$1,165	$—	$—	$1,165
Total gain (loss) included in revenue	—	—	—	—
Total gain (loss) included in AOCI	182	—	—	182
Purchases	—	—	48	48
Issuances	—	—	—	—
Settlements	—	—	—	—
Transfers into level 3 [(a)]	—	—	—	—
Transfers out of level 3[(b)(c)]	(1,347)	—	—	(1,347)
Balances at end of period	$—	$—	$48	$48
Changes in unrealized gains (losses) relating to instruments still held as of period-end	$—	$—	$48	$48

	Three Months Ended March 31, 2011 Commodity Derivatives
Balance as of beginning of period	$266
Unrealized losses	(160)
Unrealized gains	—
Settlements	—
Transfers into level 3 [(a)]	—
Transfers out of level 3[(b)]	—
Balance at end of period	$106
Changes in unrealized gains (losses) relating to instruments still held as of period-end	$(159)

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(a) Transfers into Level 3 would occur when significant inputs used to value the derivative instruments become less observable such as a significant decrease in the frequency and volume in which the instrument is traded, negatively impacting the availability of observable pricing inputs.

(b) Transfers out of Level 3 would occur when the significant inputs become more observable such as the time between the valuation date and the delivery date of a transaction becomes shorter, positively impacting the availability of observable pricing inputs.

(c) Previously, we utilized pricing methodologies developed by our Energy Marketing segment to value our Oil and Gas derivatives. Oil and Gas now obtains available observable inputs including quoted prices traded on active exchanges from multiple sources to value our options. Therefore, options in the Oil and Gas segment have been reclassified from Level 3 to Level 2.

Fair Value Measures

As required by accounting standards for derivatives and hedges, fair values within the following tables are presented on a gross basis and do not reflect the netting of asset and liability positions permitted in accordance with accounting standards for offsetting and under terms of our master netting agreements. Further, the amounts do not include net cash collateral on deposit in margin accounts at March 31, 2012, December 31, 2011, and March 31, 2011, to collateralize certain financial instruments, which are included in Derivative assets and/or Derivative liabilities.

Therefore, the gross balances are not indicative of either our actual credit exposure or net economic exposure. Additionally, the amounts below will not agree with the amounts presented on our Condensed Consolidated Balance Sheets, nor will they correspond to the fair value measurements presented in Note 13.

The following tables present the fair value and balance sheet classification of our derivative instruments (in thousands):

As of March 31, 2012

	Balance Sheet Location	Fair Value of Asset Derivatives	Fair Value of Liability Derivatives
Derivatives designated as hedges:			
Commodity derivatives	Derivative assets — current	$8,662	$—
Commodity derivatives	Derivative assets — non-current	854	—
Commodity derivatives	Derivative liabilities — current	—	2,904
Commodity derivatives	Derivative liabilities — non-current	—	1,084
Interest rate swaps	Derivative liabilities — current	—	6,777
Interest rate swaps	Derivative liabilities — non-current	—	18,441
Total derivatives designated as hedges		$9,516	$29,206
Derivatives not designated as hedges:			
Commodity derivatives	Derivative assets — current	$—	$8,436
Commodity derivatives	Derivative assets — non-current	—	(27)
Commodity derivatives	Derivative liabilities — current	—	—
Commodity derivatives	Derivative liabilities — non-current	—	6,407
Interest rate swaps	Derivative liabilities — current	—	66,708
Interest rate swaps	Derivative liabilities — non-current	—	17,237
Total derivatives not designated as hedges		$—	$98,761

As of December 31, 2011

	Balance Sheet Location	Fair Value of Asset Derivatives	Fair Value of Liability Derivatives
Derivatives designated as hedges:			
Commodity derivatives	Derivative assets — current	$8,739	$—
Commodity derivatives	Derivative assets — non-current	1,919	—
Commodity derivatives	Derivative liabilities — current	—	2,559
Commodity derivatives	Derivative liabilities — non-current	—	818
Interest rate swaps	Derivative liabilities — current	—	6,513
Interest rate swaps	Derivative liabilities — non-current	—	20,363
Total derivatives designated as hedges		$10,658	$30,253
Derivatives not designated as hedges:			
Commodity derivatives	Derivative assets — current	$—	$9,572
Commodity derivatives	Derivative assets — non-current	—	(52)
Commodity derivatives	Derivative liabilities — current	—	—
Commodity derivatives	Derivative liabilities — non-current	—	7,156
Interest rate swaps	Derivative liabilities — current	—	75,295
Interest rate swaps	Derivative liabilities — non-current	—	20,696
Total derivatives not designated as hedges		$—	$112,667

As of March 31, 2011

	Balance Sheet Location	Fair Value of Asset Derivatives	Fair Value of Liability Derivatives
Derivatives designated as hedges:			
Commodity derivatives	Derivative assets — current	$6,757	$—
Commodity derivatives	Derivative assets — non-current	975	—
Commodity derivatives	Derivative liabilities — current	—	4,688
Commodity derivatives	Derivative liabilities — non-current	—	2,835
Interest rate swaps	Derivative liabilities — current	—	6,769
Interest rate swaps	Derivative liabilities — non-current	—	12,955
Total derivatives designated as hedges		$7,732	$27,247
Derivatives not designated as hedges:			
Commodity derivatives	Derivative assets — current	$—	$2,665
Commodity derivatives	Derivative assets — non-current	—	(209)
Commodity derivatives	Derivative liabilities — current	—	—
Commodity derivatives	Derivative liabilities — non-current	—	—
Interest rate swaps	Derivative liabilities — current	—	48,515
Interest rate swaps	Derivative liabilities — non-current	—	—
Total derivatives not designated as hedges		$—	$50,971

A description of our derivative activities is included in Note 13. The following tables present the impact that derivatives had on our Condensed Consolidated Statements of Income and Comprehensive Income.

Cash Flow Hedges

The impact of cash flow hedges on our Condensed Consolidated Statements of Income and Comprehensive Income was as follows (in thousands):

Three Months Ended March 31, 2012

Derivatives in Cash Flow Hedging Relationships	Amount of Gain/(Loss) Recognized in AOCI Derivative (Effective Portion)	Location of Gain/(Loss) Reclassified from AOCI into Income (Effective Portion)	Amount of Reclassified Gain/(Loss) from AOCI into Income (Effective Portion)	Location of Gain/(Loss) Recognized in Income on Derivative (Ineffective Portion)	Amount of Gain/(Loss) Recognized in Income on Derivative (Ineffective Portion)
Interest rate swaps	$(762)	Interest expense	$(1,822)		$—
Commodity derivatives	1,283	Revenue	3,009		—
Total	$521		$1,187		$—

Three Months Ended March 31, 2011

Derivatives in Cash Flow Hedging Relationships	Amount of Gain/(Loss) Recognized in AOCI Derivative (Effective	Location of Gain/(Loss) Reclassified from AOCI into Income (Effective	Amount of Reclassified Gain/(Loss) from AOCI into Income (Effective	Location of Gain/(Loss) Recognized in Income on Derivative (Ineffective	Amount of Gain/(Loss) Recognized in Income on Derivative (Ineffective

	Portion)	Portion)	Portion)	Portion)	Portion)
Interest rate swaps	$298	Interest expense	$(1,892)		$—
Commodity derivatives	(4,083)	Revenue	1,031		—
Total	$(3,785)		$(861)		$—

Derivatives Not Designated as Hedge Instruments

The impact of derivative instruments that have not been designated as hedging instruments on our Condensed Consolidated Statements of Income and Comprehensive Income was as follows (in thousands):

Derivatives Not Designated as Hedging Instruments	Location of Gain/(Loss) on Derivatives Recognized in Income	Three Months Ended March 31, 2012 Amount of Gain/(Loss) on Derivatives Recognized in Income
Interest rate swaps - unrealized	Unrealized gain (loss) on interest rate swaps, net	$12,045
Interest rate swaps - realized	Interest expense	(3,205)
		$8,840

Derivatives Not Designated as Hedging Instruments	Location of Gain/(Loss) on Derivatives Recognized in Income	Three Months Ended March 31, 2011 Amount of Gain/(Loss) on Derivatives Recognized in Income
Interest rate swaps - unrealized	Unrealized gain (loss) on interest rate swaps, net	$5,465
Interest rate swaps - realized	Interest expense	(3,352)
		$2,113

(15) FAIR VALUE OF FINANCIAL INSTRUMENTS

The estimated fair values of our financial instruments are as follows (in thousands) as of:

	March 31, 2012		December 31, 2011		March 31, 2011	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Cash and cash equivalents (a)	$56,132	$56,132	$21,628	$21,628	$26,418	$26,418
Restricted cash (a)	$8,960	$8,960	$9,254	$9,254	$3,406	$3,406
Total derivative assets (b)	$18,758	$18,758	$20,554	$20,554	$8,996	$8,996
Total derivative liabilities (b)	$119,558	$119,558	$133,400	$133,400	$75,762	$75,762
Notes payable (a)	$225,000	$225,000	$345,000	$345,000	$287,000	$287,000
Long-term debt, including current maturities (c)	$1,280,993	$1,439,724	$1,282,882	$1,464,289	$1,189,084	$1,260,539

(a) Carrying value approximates fair value due to short-term maturities and therefore is classified in Level 1 in the fair value hierarchy.
(b) See Note 14 for information on classification within the fair value hierarchy.
(c) Long-term debt is valued based on observable inputs available either directly or indirectly for similar liabilities in active markets and therefore is classified in Level 2 in the fair value hierarchy.

The following methods and assumptions were used to estimate the fair value of each class of our financial instruments.

Cash and Cash Equivalents

Included in cash and cash equivalents is cash, overnight repurchase agreement accounts, money market funds and term deposits. As part of our cash management process, excess operating cash is invested in overnight repurchase agreements with our bank. Repurchase agreements are not deposits and are not insured by the U.S. Government, the FDIC or any other government agency and involve investment risk including possible loss of principal. We believe however, the market risk arising from holding these financial instruments is minimal. The carrying amount for cash and cash equivalents approximates fair value due to the short-term maturity of these instruments.

Restricted Cash

Restricted cash represents amounts required by Black Hills Wyoming project financing agreements. Of this total, $4.8 million, $0.0 million and $0.0 million for March 31, 2012, December 31, 2011 and March 31, 2011, respectively, were held in uninsured term deposits held at a Canadian bank.

Derivative Financial Instruments

These instruments are carried at fair value. These inputs include unadjusted quoted prices where available, prices published by various third party providers, and, when necessary, internally developed adjustments. In many cases, the internally developed prices are corroborated with external sources. Certain Company transactions take place in markets with limited liquidity and limited price visibility. Descriptions of the various instruments we use and the valuation methods employed are included in Notes 13 and 14.

Notes Payable

The carrying amounts of our notes payable approximate fair value due to their variable interest rates with short reset periods.

Long-term Debt

Our debt instruments are marked to fair value using the market valuation approach. The fair value for our fixed rate debt instruments is estimated based on quoted market prices and yields for debt instruments having similar maturities and debt ratings. The carrying amounts of our variable rate debt approximate fair value due to the variable interest rates with short reset periods.

(16) COMMITMENTS AND CONTINGENCIES

There have been no significant changes to commitments and contingencies from those previously disclosed in Note 19 of our Notes to the Consolidated Financial Statements in our 2011 Annual Report on Form 10-K.

(17) DISCONTINUED OPERATIONS

On February 29, 2012, we sold the outstanding stock of our Energy Marketing segment, Enserco Energy Inc. The transaction was completed through a stock purchase agreement and certain other ancillary agreements. Net cash proceeds were approximately $166.3 million, subject to final post-closing adjustments that are expected to be settled during the second quarter of 2012. The proceeds represent $108.8 million received from Twin Eagle and $57.5 million cash retained from Enserco prior to closing. We recorded an after-tax loss on sale of $1.6 million, including transaction related costs net of tax of $2.2 million.

The accompanying Condensed Consolidated Financial Statements have been classified to reflect Enserco as discontinued operations. For comparative purposes, all prior periods presented have been restated to reflect the classification.

Operating results of the Energy Marketing segment included in Income (loss) from discontinued operations, net of tax on the accompanying Condensed Consolidated Statements of Income and Comprehensive Income were as follows (in thousands):

	For the Three Months Ended	
	March 31, 2012	March 31, 2011
Revenue	$(604)	$2,465
Pre-tax income (loss) from discontinued operations	(5,836)	(3,174)
Pre-tax gain (loss) on sale	(2,453)	—
Income tax (expense) benefit	2,805	1,016
Income (loss) from discontinued operations, net of tax	$(5,484)	$(2,158)

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Indirect corporate costs and inter-segment interest expenses totaling $1.6 million and $0.5 million for the three months ended March 31, 2012 and March 31, 2011, respectively, are reclassified from the Energy Marketing segment to the Corporate segment in continuing operations on the accompanying Condensed Consolidated Statements of Income and Comprehensive Income.

Net assets of the Energy Marketing segment included in Assets/Liabilities of discontinued operations in the accompanying Condensed Consolidated Balance Sheets were as follows (in thousands) as of:

	December 31, 2011	March 31, 2011
Other current assets	$280,221	$243,473
Derivative assets, current and non-current	52,859	45,432
Property, plant and equipment, net	5,828	4,750
Goodwill	1,435	1,435
Other non-current assets	508	631
Other current liabilities	(132,951)	(129,706)
Derivative liabilities, current and non-current	(26,084)	(30,932)
Other non-current liabilities	(14,894)	(2,652)
Net assets	$166,922	$132,431

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ITEM 2. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

We are an integrated energy company operating principally in the United States with two major business groups — Utilities and Non-regulated Energy. We report our business groups in the following financial segments:

Business Group	Financial Segment
Utilities	Electric Utilities Gas Utilities
Non-regulated Energy*	Oil and Gas Power Generation Coal Mining

* In February 2012, we sold Enserco, our Energy Marketing segment, through a stock purchase agreement and therefore classified the segment as discontinued operations.

Our Utilities Group consists of our Electric and Gas Utilities segments. Our Electric Utilities segment generates, transmits and distributes electricity to approximately 201,500 customers in South Dakota, Wyoming, Colorado and Montana and includes the operations of Cheyenne Light and its approximately 34,800 natural gas customers in Wyoming. Our Gas Utilities serve approximately 528,800 natural gas customers in Colorado, Iowa, Kansas and Nebraska. Our Non-regulated Energy Group consists of our Oil and Gas, Power Generation and Coal Mining segments. Our Oil and Gas segment primarily engages in exploration, development and production of crude oil and natural gas, primarily in the Rocky Mountain region. Our Power Generation segment produces electric power from our generating plants and sells the electric capacity and energy primarily to other utilities under long-term contracts. Our Coal Mining segment produces coal at our coal mine near Gillette, Wyoming and sells the coal primarily to on-site, mine-mouth power generation facilities.

Certain industries in which we operate are highly seasonal, and revenue from, and certain expenses for, such operations may fluctuate significantly among quarterly periods. Demand for electricity and natural gas is sensitive to seasonal cooling, heating and industrial load requirements, as well as changes in market prices. In particular, the normal peak usage season for gas utilities is November through March, and significant earnings variances can be expected between the Gas Utilities segment's peak and off-peak seasons. Due to this seasonal nature, our results of operations for the three months ended March 31, 2012 and 2011, and our financial condition as of March 31, 2012, December 31, 2011, and March 31, 2011 are not necessarily indicative of the results of operations and financial condition to be expected as of or for any other period.
See Forward-Looking Information in the Liquidity and Capital Resources section of this Item 2, beginning on Page 49.

The following business group and segment information does not include intercompany eliminations. Minor differences in amounts may result due to rounding. All amounts are presented on a pre-tax basis unless otherwise indicated. Information has been revised to remove information related to the operations of our Energy Marketing segment, now classified as discontinued operations, as a result of its sale on February 29, 2012.

Results of Operations

Executive Summary, Significant Events and Overview

Three Months Ended March 31, 2012 Compared to Three Months Ended March 31, 2011. Income from continuing operations for the three months ended March 31, 2012 was $35.3 million, or $0.80 per share, compared to Income from continuing operations of $29.1 million, or $0.73 per share, reported for the same period in 2011. The 2012 Income from continuing operations included a $7.8 million non-cash after-tax unrealized mark-to-market gain on certain interest rate swaps and an after-tax write-off of $1.0 million of deferred financing costs related to the previous Revolving Credit Facility. The 2011 Income from continuing operations included a $3.6 million after-tax unrealized mark-to-market gain on the same interest rate swaps.

Net income was $29.8 million, or $0.68 per share, in 2012 compared to $26.9 million, or $0.68 per share, in 2011.

	Three Months Ended March 31, 2012	2011	Increase (Decrease)
	(in thousands)		
Revenue			
Utilities	$339,691	$378,535	$(38,844)
Non-regulated Energy	56,261	41,021	15,240
Corporate	—	—	—
Intercompany eliminations	(30,101)	(18,721)	(11,380)
	$365,851	$400,835	$(34,984)
Net income (loss)			
Electric Utilities	$8,746	$10,249	$(1,503)
Gas Utilities	15,207	19,263	(4,056)
Utilities	23,953	29,512	(5,559)
Oil and Gas	13	(715)	728
Power Generation	6,914	1,186	5,728
Coal Mining	1,000	(1,298)	2,298
Non-regulated Energy	7,927	(827)	8,754
Corporate and Eliminations [(a)]	3,391	383	3,008
Income from continuing operations	35,271	29,068	6,203
Income (loss) from discontinued operations, net of tax	(5,484)	(2,158)	(3,326)
Net income (loss)	$29,787	$26,910	$2,877

(a) Financial results of our Energy Marketing segment have been classified as discontinued operations. Certain indirect corporate costs and inter-segment expenses previously charged to our Energy Marketing segment are reclassified to continuing operations and are included in the Corporate segment. See Note 17 of the Condensed Consolidated Financial Statements in this Quarterly Report on Form 10-Q.

Business Group highlights for 2012 include:

Utilities Group

- Utility results were unfavorably impacted by warmer weather. During 2012, we experienced the warmest March on record for our jurisdictions causing reduced heating degree days. Heating degree days during the period were 13% and 19% lower than weighted average norms for our Electric and Gas Utilities, respectively. When compared to colder than normal weather during the same quarter in 2011, heating degree days were 20% and 24% lower than the same period in 2011 for our Electric Utilities and our Gas Utilities, respectively.

- Colorado Electric's new $230 million, 180 MW power plant near Pueblo, Colorado began commercial operations and started serving utility customers on January 1, 2012. New rates were effective January 1, 2012 and provided an additional $5.8 million in gross margins at Colorado Electric for the three months ended March 31, 2012.

- On November 1, 2011, Cheyenne Light and Black Hills Power filed a joint request with the WPSC for a CPCN to construct and operate a new $237 million natural gas-fired electric generation facility and related gas and electric transmission in Cheyenne, WY. The proposed facility includes construction of one simple-cycle, 37 MW combustion turbine that will be wholly owned by Cheyenne Light and one combined-cycle, 95 MW unit that would be jointly owned by Cheyenne Light and Black Hills Power. Cheyenne Light would own 40 MW and Black Hills Power would own 55 MW of the combined cycle unit. Pending WPSC approval, and the timely receipt of necessary environmental and industrial siting permits, commercial operation would be expected to commence in 2014. A hearing with the WPSC is scheduled in July 2012.

- Construction by Colorado Electric is progressing on a 29 MW wind turbine project as part of its plan to meet Colorado's Renewable Energy Standard. Colorado Electric's 50% share of this project will cost approximately $26.5 million, and the project is expected to begin serving Colorado Electric customers no later than December 31, 2012. Our 50% of the total expenditures on the project were $15.4 million as of March 31, 2012.

- On April 13, 2012, the Colorado Public Utilities Commission issued its final order denying Colorado Electric's request for a certificate of public convenience and necessity to construct a third utility-owned, 88 MW natural gas-fired turbine at the existing Pueblo Airport generating location. Colorado Electric retains the right under the Colorado Clean Air – Clean Jobs Act to own the 42 megawatts of replacement generation for the W.N. Clark plant that is required to be retired on or before December 13, 2013. Colorado Electric is expected to file an electric resource plan by July 30, 2012 that will identify an alternative replacement resource for the W.N. Clark plant.

Non-regulated Energy Group

- In February 2012, we sold the outstanding stock of Enserco, our Energy Marketing segment. Net pre-tax cash proceeds were $166.3 million, subject to final post-closing adjustments that are expected to be settled during the second quarter of 2012. The proceeds represent $108.8 million received from Twin Eagle and $57.5 million cash retained from Enserco prior to close. We recorded an after-tax loss on sale of $1.6 million, including costs to sell of $2.2 million. The activities of the Energy Marketing segment have been reclassified to discontinued operations.

- Colorado IPP's new $261 million, 200 MW power plant near Pueblo, Colorado began serving customers on Jan. 1, 2012, with its output sold under a 20-year power purchase agreement to Colorado Electric.

Corporate

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On February 1, 2012, we entered into a new $500 million Revolving Credit Facility expiring February 1, 2017 at favorable terms. Deferred financing costs of $1.5 million were written off during the first quarter of 2012 relating to the previous credit facility.

- We recognized a non-cash unrealized mark-to-market gain related to certain interest rate swaps of $12.0 million for the three months ended March 31, 2012 compared to a $5.5 million unrealized mark-to-market gain on these swaps for the same period in 2011.

Utilities Group

We report two segments within the Utilities Group: Electric Utilities and Gas Utilities. The Electric Utilities segment includes the electric operations of Black Hills Power, Colorado Electric and the electric and natural gas operations of Cheyenne Light. The Gas Utilities segment includes the regulated natural gas utility operations of Black Hills Energy in Colorado, Iowa, Kansas and Nebraska.

Electric Utilities

	Three Months Ended March 31,	
	2012	2011
	(in thousands)	
Revenue — electric	$146,281	$134,870
Revenue — Cheyenne Light gas	12,888	13,399
Total revenue	159,169	148,269
Fuel, purchased power and cost of gas — electric	65,598	65,678
Purchased gas — Cheyenne Light gas	8,118	8,396
Total fuel, purchased power and cost of gas	73,716	74,074
Gross margin — electric	80,683	69,192
Gross margin — Cheyenne Light gas	4,770	5,003
Total gross margin	85,453	74,195
Operations and maintenance	39,230	37,114
Depreciation and amortization	18,932	12,824
Total operating expenses	58,162	49,938
Operating income	27,291	24,257
Interest expense, net	(13,220)	(9,944)
Other income (expense), net	718	409
Income tax benefit (expense)	(6,043)	(4,473)
Income (loss) from continuing operations	$8,746	$10,249

The following tables summarize revenue, quantities generated and purchased, quantities sold, degree days and power plant availability for our Electric Utilities:

	Three Months Ended March 31,	
Revenue - Electric (in thousands)	2012	2011
Residential	$46,562	$45,677
Commercial	49,892	46,442
Industrial	18,321	16,243
Municipal	3,788	4,061
Total Retail Revenue - Electric	118,563	112,423
Contract Wholesale - Black Hills Power	4,905	4,620
Off-system Wholesale [a]	14,019	9,840
Other Revenue	8,794	7,987
Total Revenue - Electric	$146,281	$134,870

(a) Off-system sales revenue during 2011 was deferred until a sharing mechanism was approved by the CPUC in December 2011, and recognition of 25% of the revenue commenced January 2, 2012. As a result, Colorado Electric deferred $2.9 million in off-system revenue during the three months ended March 31, 2011.

	Three Months Ended March 31,	
Quantities Generated and Purchased (in MWh)	2012	2011
Generated —		
Coal-fired	684,252	665,884
Gas and Oil-fired	1,995	1,024
Total Generated	686,247	666,908
Total Purchased	1,147,280	1,055,566
Total Generated and Purchased	1,833,527	1,722,474

	Three Months Ended March 31,	
Quantity Sold (in MWh)	2012	2011
Residential	376,317	404,633
Commercial	485,423	489,570
Industrial	221,751	213,486
Municipal	35,319	38,493
Total Retail Quantity Sold	1,118,810	1,146,182
Contract Wholesale - Black Hills Power	89,048	89,959
Total Off-system Wholesale	527,547	404,844
Total Losses and Company Use	98,122	81,489
Total Quantity Sold	1,833,527	1,722,474

Degree Days	Three Months Ended March 31, 2012			2011		
Heating Degree Days:	Actual	Variance from 30-Year Average		Actual	Variance from 30-Year Average	
Actual —						
Black Hills Power	2,711	(16	)%	3,707	12	%
Cheyenne Light	2,761	(8	)%	3,123	—	%
Colorado Electric	2,294	(13	)%	2,781	5	%
Cooling Degree Days:						
Actual —						
Black Hills Power	—	—	%	—	—	%
Cheyenne Light	—	—	%	—	—	%
Colorado Electric	—	—	%	—	—	%

Electric Utilities Power Plant Availability	Three Months Ended March 31, 2012		2011	
Coal-fired plants [(a)]	90.8	%	91.3	%
Other plants	95.0	%	98.6	%
Total availability	92.9	%	93.9	%

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(a) 2012 includes planned overhauls at Wygen II. 2011 includes a major overhaul and an unplanned outage at the PacifiCorp operated Wyodak plant.

Cheyenne Light Natural Gas Distribution

Included in the Electric Utilities is Cheyenne Light's natural gas distribution system. The following table summarizes certain operating information for these natural gas distribution operations:

	Three Months Ended March 31, 2012	2011
Revenue - Gas (in thousands):		
Residential	$7,630	$7,978
Commercial	3,810	3,807
Industrial	1,237	1,276
Other Sales Revenue	211	338
Total Revenue - Gas	$12,888	$13,399
Gross Margin (in thousands):		
Residential	$3,226	$3,388
Commercial	1,173	1,212
Industrial	164	177
Other Gross Margin	207	226
Total Gross Margin	$4,770	$5,003
Volumes Sold (Dth):		
Residential	969,678	1,068,461

Commercial	580,940	623,723
Industrial	237,140	256,521
Total Volumes Sold	1,787,758	1,948,705

Three Months Ended March 31, 2012 Compared to Three Months Ended March 31, 2011. Income from continuing operations for the Electric Utilities was $8.7 million for the three months ended March 31, 2012 compared to $10.2 million for the three months ended March 31, 2011 as a result of:

Gross margin increased $11.3 million primarily due to a $9.3 million increase related to rate adjustments that include a return on significant capital investments specifically at Colorado Electric, and a $0.6 million increase in off-system sales mainly from higher quantities sold, partially offset by a $2.8 million decrease due to lower quantities sold as a result of lower customer demand.

Operations and maintenance increased $2.1 million primarily due to higher property taxes and increased corporate allocations resulting from the generating facility in Pueblo, Colorado, partially offset by lower maintenance costs.

Depreciation and amortization increased $6.1 million primarily due to a higher asset base including additional depreciation associated with the 180 MW generating facility constructed in Pueblo, Colorado and depreciation of the capital lease assets associated with the 200 MW generating facility providing capacity and energy from Colorado IPP.

Interest expense, net increased $3.3 million primarily due to lower capitalized interest associated with the completed construction of the Pueblo generating facility in December 2011.

Other income (expense), net was comparable to the same period in the prior year.

Income tax benefit (expense): The effective tax rate increased due to unfavorable state income tax true-up adjustments that may not occur in the future and the impact of research and development credits not being renewed.

Gas Utilities

	Three Months Ended March 31, 2012	2011
	(in thousands)	
Natural gas — regulated	$172,169	$223,032
Other — non-regulated services	8,353	7,234
Total revenue	180,522	230,266
Natural gas — regulated	108,116	149,503
Other — non-regulated services	3,869	3,626
Total cost of sales	111,985	153,129
Gross margin	68,537	77,137
Operations and maintenance	31,299	34,560
Depreciation and amortization	6,157	6,021
Total operating expenses	37,456	40,581
Operating income (loss)	31,081	36,556
Interest expense, net	(6,540)	(6,972)
Other income (expense), net	11	25

Income tax benefit (expense)	(9,345)	(10,346)
Income (loss) from continuing operations	$15,207	$19,263

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The following tables summarize revenue, gross margin, volumes sold and degree days for our Gas Utilities:

Revenue (in thousands)	Three Months Ended March 31,	
	2012	2011
Residential	$118,933	$156,769
Commercial	40,802	54,730
Industrial	2,008	2,145
Transportation	7,263	8,079
Other Sales Revenue	3,163	1,309
Total Regulated Revenue	172,169	223,032
Non-regulated Services	8,353	7,234
Total Revenue	$180,522	$230,266

Gross Margin (in thousands)	Three Months Ended March 31,	
	2012	2011
Residential	$42,592	$51,396
Commercial	10,766	12,571
Industrial	384	407
Transportation	7,264	8,079
Other Sales Margins	3,048	1,076
Total Regulated Gross Margin	64,054	73,529
Non-regulated Services	4,483	3,608
Total Gross Margin	$68,537	$77,137

Volumes Sold (in Dth)	Three Months Ended March 31,	
	2012	2011
Residential	13,767,358	17,534,411
Commercial	5,528,225	7,073,483
Industrial	369,492	334,991
Transportation	18,050,184	16,286,552
Other Volumes	24,450	44,985
Total Volumes Sold	37,739,709	41,274,422

	Three Months Ended March 31, 2012	
Heating Degree Days:	Actual	Variance From Normal
Colorado	2,350	(16)%
Nebraska	2,400	(21)%
Iowa	2,799	(20)%
Kansas [a]	2,040	(18)%
Combined [b]	2,432	(19)%

	Three Months Ended March 31, 2011	
Heating Degree Days:	Actual	Variance From Normal
Colorado	2,761	(4)%
Nebraska	3,281	2%
Iowa	3,694	—%
Kansas [a]	2,625	2%
Combined [b]	3,212	1%

(a) Our gross margin in Kansas utilizes normal degree days due to an approved weather normalization mechanism.
(b) The combined heating degree days are calculated based on a weighted average of total customers by state.

Our Gas Utilities are highly seasonal and sales volumes vary considerably with weather and seasonal heating and industrial loads. Over 70% of our Gas Utilities' revenue and margins are expected in the first and fourth quarters of each year. Therefore, revenue for and certain expenses of these operations fluctuate significantly among quarters. Depending upon the state jurisdiction in which our Gas Utilities operate, the winter heating season begins around November 1 and ends around March 31.

Three Months Ended March 31, 2012 Compared to Three Months Ended March 31, 2011. Income from continuing operations for the Gas Utilities was $15.2 million for the three months ended March 31, 2012 compared to Income from continuing operations of $19.3 million for the three months ended March 31, 2011 as a result of:

Gross margin decreased $8.6 million primarily due to a $7.2 million impact from milder weather than in the same period in the prior year. Heating degree days were 24% lower for the three months ended March 31, 2012 compared to the same period in the prior year and 19% lower than normal.

Operations and maintenance decreased $3.3 million primarily due to decreased bad debt costs and cost efficiencies.

Depreciation and amortization was comparable to the same period in the prior year.

Interest expense, net decreased $0.4 million primarily due to lower interest rates.

Other income (expense), net was comparable to the same period in the prior year.

Income tax benefit (expense): The effective tax rate increased as a result of an unfavorable state income tax true-up adjustment that may not occur in the future and lower pre-tax net income. For the period ended March 31, 2011, the effective tax rate was favorably impacted as a result of federal income tax related research and development credits and a flow-through tax adjustment involving Iowa Gas.

Regulatory Matters — Utilities Group

The following summarizes our recent state and federal rate case and initial surcharge orders (dollars in millions):

	Type of Service	Date Requested	Date Effective	Revenue Amount Requested	Revenue Amount Approved	Return on Equity	Approved Capital Structure Equity	Approved Capital Structure Debt
Nebraska Gas (1)	Gas	12/2009	9/2010	$12.1	$8.3	10.1 %	52.0 %	48.0 %
Iowa Gas (2)	Gas	6/2010	2/2011	$4.7	$3.4	Global Settlement	Global Settlement	Global Settlement
Colorado Electric (2)	Electric	4/2011	1/2012	$40.2	$28.0	9.8% - 10.2%	49.1 %	50.9 %
Cheyenne Light (3)	Electric/Gas	12/2011	Pending	$8.5	Pending	Pending	Pending	Pending
Black Hills Power (2)	Electric	1/2011	6/2011	Not Applicable	$3.1	Not Applicable	Not Applicable	Not Applicable

(1) In December 2009, Nebraska Gas filed a rate case with the NPSC and interim rates went into effect on March 1, 2010. In August 2010, NPSC issued a decision approving an annual revenue increase of approximately $8.3 million, based on a return on equity of 10.1% with a capital structure of 52% equity effective on September 1, 2010. A refund to customers for the difference between interim rates and approved rates was completed in the first quarter of 2011. The Nebraska Public Advocate filed an appeal with the District Court which has been denied. Subsequently, the Nebraska Public Advocate filed a notice of appeal in the Court of Appeals. On March 20, 2012 the Court of Appeals affirmed the earlier decision of the District Court. However, the Nebraska Public Advocate petitioned the Nebraska Supreme Court to hear an appeal in April 2012.

(2) These rate cases were previously described in our 2011 Annual Report filed on Form 10-K.

(3) Cheyenne Light filed requests on December 2, 2011, for electric and natural gas revenue increases with the WPSC seeking a $5.9 million increase in annual electric revenue and a $2.6 million increase in annual natural gas revenue. A procedural schedule has been published and a public hearing with the WPSC is scheduled for the week of June 18, 2012.

Non-regulated Energy Group

We report three segments within our Non-regulated Energy Group: Oil and Gas, Coal Mining and Power Generation. For more than 15 years, we also owned and operated Enserco, an energy marketing business that engages in natural gas, crude oil, coal, power and environmental marketing and trading in the United States and Canada. We sold Enserco on February 29, 2012 which resulted in our Energy Marketing segment being classified as discontinued operations. For comparative purposes, all prior periods presented have been restated to reflect the classification of this segment as discontinued operations.

Oil and Gas

	Three Months Ended March 31, 2012	2011

	(in thousands)	
Revenue	$21,645	$17,906
Operations and maintenance	10,834	10,567
Depreciation, depletion and amortization	9,323	7,321
Total operating expenses	20,157	17,888
Operating income (loss)	1,488	18
Interest expense	(1,605)	(1,383)
Other income (expense), net	29	(185)
Income tax benefit (expense)	101	835
Income (loss) from continuing operations	$13	$(715)

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The following tables provide certain operating statistics for our Oil and Gas segment:

	Three Months Ended March 31,	
	2012	2011
Production:		
Bbls of oil sold	145,477	103,550
Mcf of natural gas sold	2,388,475	2,011,167
Gallons of NGL sold	814,585	864,440
Mcf equivalent sales	3,377,706	2,755,958

	Three Months Ended March 31,	
	2012	2011
Average price received: [(a)]		
Oil/Bbl	$77.99	$66.83
Gas/Mcf	$3.61	$4.65
NGL/gallon	$0.95	$0.92
Depletion expense/Mcfe	$2.47	$2.36

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(a) Net of hedge settlement gains and losses

The following is a summary of certain average operating expenses per Mcfe:

	Three Months Ended March 31, 2012				Three Months Ended March 31, 2011			
Producing Basin	LOE	Gathering, Compression and Processing	Production Taxes	Total	LOE	Gathering, Compression and Processing	Production Taxes	Total
San Juan	$0.97	$0.32	$0.36	$1.65	$1.25	$0.46	$0.55	$2.26
Piceance	(0.03)	0.49	0.15	0.61	0.68	0.80	0.25	1.73
Powder River	1.38	—	1.31	2.69	1.31	—	1.29	2.60
Williston	0.71	—	1.25	1.96	0.26	—	1.50	1.76
All other properties	1.68	—	0.08	1.76	1.66	—	0.40	2.06
Total weighted average	$0.89	$0.21	$0.60	$1.70	$1.18	$0.28	$0.74	$2.20

Three Months Ended March 31, 2012 Compared to Three Months Ended March 31, 2011. Income from continuing operations for the Oil and Gas segment was $0.0 million for the three months ended March 31, 2012 compared to Loss from continuing operations of $0.7 million for the same period in 2011 as a result of:

Revenue increased primarily due to a 17% increase in the average hedged price received for crude oil sales along with a 40% increase in crude oil volume sold. Crude oil production increases reflect volumes from new wells in our ongoing drilling program in the Bakken shale formation. A 17% increase in natural gas and NGL volumes, due mainly to the completion of three Mancos formation test wells in the San Juan and Piceance Basins, was partially offset by a 22% decrease in average hedged price received for natural gas.

Operations and maintenance costs were comparable to the same period in the prior year.

Depreciation, depletion and amortization increased $2.0 million primarily due to a higher depletion rate per Mcfe on higher volumes. The increased depletion rate is primarily driven by higher capital costs for our Bakken oil drilling program.

Interest expense, net was comparable to the same period in the prior year.

Other income (expense), net was comparable to the same period in the prior year.

Income tax (expense) benefit: For 2012, the benefit generated by percentage depletion had a greater impact on the effective tax rate compared to the same period in 2011.

Coal Mining

	Three Months Ended March 31,	
	2012	2011
	(in thousands)	
Revenue	$14,989	$15,495
Operations and maintenance	11,478	14,572
Depreciation, depletion and amortization	3,696	4,618
Total operating expenses	15,174	19,190
Operating income (loss)	(185)	(3,695)
Interest income, net	755	960
Other income	881	569
Income tax benefit (expense)	(451)	868
Income (loss) from continuing operations	$1,000	$(1,298)

The following table provides certain operating statistics for our Coal Mining segment (in thousands):

	Three Months Ended March 31,	
	2012	2011
Tons of coal sold	1,103	1,370
Cubic yards of overburden moved	2,642	3,455

Three Months Ended March 31, 2012 Compared to Three Months Ended March 31, 2011. Income from continuing operations for the Coal Mining segment was $1.0 million for the three months ended March 31, 2012 compared to Loss from continuing operations of $1.3 million for the same period in 2011, as a result of:

Revenue decreased $0.5 million primarily due to a 19% decrease in tons sold due to the expiration of our train load-out contract and a planned outage at the Wygen II facility, partially offset by a 20% increase in average price per ton and increased volumes sold to the Wyodak plant that experienced an outage in 2011. The higher average sales price reflects the impact of price escalators and expiration of our train load-out contract. Approximately 50% of our coal production was sold under contracts that include price adjustments based on actual mining cost increases.

Operations and maintenance decreased $3.1 million primarily from lower costs related to a train-load out contract that expired at the end of 2011, reducing tons moved.

Depreciation, depletion and amortization decreased $0.9 million primarily due to a lower asset base.

Interest income, net was comparable to the same period in the prior year.

Other income was comparable to the same period in the prior year.

Income tax benefit (expense): The change in the effective tax rate was primarily due to the impact of percentage depletion.

Power Generation

	Three Months Ended March 31,	
	2012	2011
	(in thousands)	
Revenue	$19,627	$7,620
Operating, general and administrative costs	7,132	4,188
Depreciation and amortization	1,114	1,064
Total operating expense (income)	8,246	5,252
Operating income	11,381	2,368
Interest expense, net	(4,743)	(1,791)
Other (expense) income	5	1,204
Income tax (expense) benefit	271	(595)
Income (loss) from continuing operations	$6,914	$1,186

The following table provides certain operating statistics for our plants within the Power Generation segment:

	Three Months Ended March 31,	
	2012	2011
Contracted power plant fleet availability:		
Coal-fired plant	100.0%	100.0%
Natural gas-fired plants	99.6%	100.0%
Total availability	99.7%	100.0%

Three Months Ended March 31, 2012 Compared to Three Months Ended March 31, 2011. Income from continuing operations for the Power Generation segment was $6.9 million for the three months ended March 31, 2012 compared to Income from continuing operations of $1.2 million for the same period in 2011 as a result of:

Revenue increased due to the sale of capacity and energy to Colorado Electric upon commencement of commercial operation of our 200 MW generating facility in Pueblo, Colorado.

Operations and maintenance increased $2.9 million primarily due to the costs to operate our 200 MW generating facility in Pueblo, Colorado, which began serving customers on January 1, 2012.

Depreciation and amortization were consistent with prior year. The new generating facility's PPA to supply capacity and energy to Colorado Electric is accounted for as a capital lease under GAAP; as such, depreciation expense for the facility is recorded at Colorado Electric for segment reporting purposes.

Interest expense, net increased due to the decrease in capitalized interest as a result of the completion of construction of our generating facility in Pueblo, Colorado.

Other (expense) income, net in 2011 included earnings from our partnership investment in certain Idaho generating facilities and a gain on sale of our ownership interest in the partnership which did not reoccur in 2012.

Income tax (expense) benefit: The effective tax rate was impacted by a favorable state tax true-up that included certain tax credits. Such credits are the result of meeting certain applicable state requirements including the ability to utilize these incentives. The incentives pertain to qualified plant expenditures related to investment and research and development.

Corporate

Three Months Ended March 31, 2012 Compared to Three Months Ended March 31, 2011. Income from continuing operations for Corporate was $3.4 million for the three months ended March 31, 2012 compared to Income from continuing operations of $0.5 million for the three months ended March 31, 2011 primarily as a result of an unrealized, non-cash mark-to-market gain on certain interest rate swaps for the quarter ended March 31, 2012 of approximately $12.0 million compared to a $5.5 million unrealized, mark-to-market non-cash gain on these interest rate swaps in the prior year.

Corporate was allocated after-tax costs of $1.6 million related to on-going costs associated with our Energy Marketing segment for the three months ended March 31, 2012 which could not be included in discontinued operations compared to after-tax costs of $0.5 million for the three months ended March 31, 2011.

Discontinued Operations

Three Months Ended March 31, 2012 Compared to Three Months Ended March 31, 2011.

On February 29, 2012, we sold the outstanding stock of our Energy Marketing segment, Enserco. The transaction was completed through a stock purchase agreement and certain other ancillary agreements. Cash proceeds were approximately $166.3 million, subject to final post-closing adjustments that are expected to be settled during the second quarter of 2012. The proceeds represent $108.8 million received from Twin Eagle and $57.5 million cash retained from Enserco prior to closing. We recorded an after-tax loss on sale of $1.6 million, including transaction related costs of $2.2 million.

Loss from discontinued operations, net of tax was $5.5 million, including an after-tax loss on the sale of $1.6 million, for the three months ended March 31, 2012 compared to a loss from discontinued operations, net of tax of $2.2 million for the three months ended March 31, 2011.

Critical Accounting Policies

There have been no material changes in our critical accounting policies from those reported in our 2011 Annual Report on Form 10-K filed with the SEC. For more information on our critical accounting policies, see Part II, Item 7 of our 2011 Annual Report on Form 10-K.

Liquidity and Capital Resources

Cash Flow Activities

The following table summarizes our cash flows for the three months ended March 31, 2012 and 2011 (in thousands):

Cash provided by (used in):	2012	2011	Increase (Decrease)
Operating activities	$96,065	$111,271	$(15,206)
Investing activities	$41,466	$(121,758)	$163,224
Financing activities	$(140,167)	$22,065	$(162,232)

Year-to-Date 2012 Compared to Year-to-Date 2011

Operating Activities

Net cash provided by operating activities was $15.2 million lower for the three months ended March 31, 2012 than for the same period in 2011 primarily attributable to:

- Cash earnings (net income plus non-cash adjustments) were $7.1 million higher for the three months ended March 31, 2012 than for the same period the prior year.

- Net inflows from operating assets and liabilities were $6.1 million for the three months ended March 31, 2012, a decrease of $5.0 million from the same period in the prior year. In addition to normal working capital changes, the decrease primarily related to decreased gas volumes due to warmer weather and to lower gas prices.

- Cash contributions to the defined benefit pension plan were $25.0 million in 2012 compared to $0.0 million in 2011.

Investing Activities

Net cash provided by investing activities was $163.2 million higher for the three months ended March 31, 2012 than in the same period in 2011 reflecting cash proceeds received from the sale of Enserco of $108.8 million and reduced capital expenditures of $54.0 million due to the completion of construction of 180 MW of natural gas-fired electric generation at Colorado Electric and 200 MW of natural gas-fired electric generation at Black Hills Colorado IPP in 2011.

Financing Activities

Net cash used in financing activities was $162.2 million higher for the three months ended March 31, 2012 than in the same period in 2011 primarily due to applying the proceeds from the sale of Enserco to pay down short-term borrowings on the Revolving Credit Facility of approximately $110 million. Cash dividends on common stock of $16.3 million were paid in 2012 compared to cash dividends paid of $14.4 million in 2011.

Dividends

Dividends paid on our common stock totaled $16.3 million for the three months ended March 31, 2012, or $0.37 per share. On April 24, 2012, our Board of Directors declared an additional quarterly dividend of $0.37 per share payable June 1, 2012, which is equivalent to an annual dividend rate of $1.48 per share. The determination of the amount of future cash dividends, if any, to be declared and paid will depend upon, among other things, our financial condition, funds from operations, the level of our capital expenditures, restrictions under our credit facility and our future business prospects.

Financing Transactions and Short-Term Liquidity

Our principal sources of short-term liquidity are our Revolving Credit Facility and cash provided by operations. In addition to availability under our Revolving Credit Facility described below, as of March 31, 2012, we had approximately $56 million of unrestricted cash. The net cash proceeds from the Enserco sale were utilized to reduce short-term debt by approximately $110 million with the remainder included in our March 31, 2012 cash balance.

Revolving Credit Facility

Our $500 million Revolving Credit Facility expiring February 1, 2017 can be used for the issuance of letters of credit, to fund working capital needs and for general corporate purposes. Borrowings are available under a base rate option or a Eurodollar option. The cost of borrowings or letters of credit is determined based upon our credit ratings. At current ratings levels, the margins for base rate borrowings, Eurodollar borrowings and letters of credit were 0.50%, 1.50% and 1.50%, respectively. The facility contains a commitment fee that will be charged on the unused amount of the Facility. Based upon current credit ratings, the fee is 0.25%. The facility contains an accordion feature which allows us, with the consent of the administrative agent, to increase the capacity of the facility to $750 million.

At March 31, 2012, we had borrowings of $75 million and letters of credit outstanding of $41 million on our Revolving Credit Facility. Available capacity remaining was approximately $384 million at March 31, 2012.

The Revolving Credit Facility contains customary affirmative and negative covenants, such as limitations on the creation of new indebtedness and on certain liens, restrictions on certain transactions, maintenance of certain financial covenants and a recourse leverage ratio not to exceed 0.65 to 1.00. At March 31, 2012, our long-term debt ratio was 50.9%, our total debt leverage ratio (long-term debt and short-term debt) was 55.2%, and our recourse leverage ratio was approximately 56.4%. We were in compliance with these covenants as of March 31, 2012.

In addition to covenant violations, an event of default under the Revolving Credit Facility may be triggered by other events, such as a failure to make payments when due or a failure to make payments when due in respect of, or a failure to perform obligations relating to, other debt obligations of $35 million or more. Subject to applicable cure periods (none of which apply to a failure to timely pay indebtedness), an event of default would permit the lenders to restrict our ability to further access the credit facility for loans or new letters of credit, and could require both the immediate repayment of any outstanding principal and interest and the cash collateralization of outstanding letter of credit obligations.

Corporate Term Loans

In June 2011, we entered into a one-year $150 million unsecured, single draw, term loan due on June 24, 2012. The cost of borrowing under the loan is based on a spread of 1.25% over LIBOR (1.50% at March 31, 2012). The covenants are substantially the same as those included in the Revolving Credit Facility with an additional requirement to maintain a minimum consolidated net worth. We were in compliance with these covenants as of March 31, 2012.

In December 2010, we entered into a one-year $100.0 million term loan with J.P. Morgan and Union Bank due in December 2011. On September 30, 2011, we extended that term loan for two years under the existing terms to September 13, 2013. The cost of borrowing under this Term Loan is based on a spread of 1.375% over LIBOR (1.625% at March 31, 2012). The covenants are substantially the same as those included in the Revolving Credit Facility with an additional requirement to maintain a minimum consolidated net worth. We were in compliance with these covenants as of March 31, 2012.

Repayment of Long-term Debt

On March 28, 2012, Black Hills Power provided notice to the trustee of its intent to call the Pollution Control Refund Revenue Bonds. These bonds were originally due to mature on October 1, 2014. The principal amount due on the bonds has been reclassified to Current maturities of long-term debt on the accompanying Condensed Consolidated Balance Sheets. Repayment of $6.5 million principal and accrued interest will be made on May 15, 2012.

Dividend Restrictions

Due to our holding company structure, substantially all of our operating cash flows are provided by dividends paid or distributions made by our subsidiaries. The cash to pay dividends to our stockholders is derived from these cash flows. As a result of certain statutory limitations or regulatory or financing agreements, we could have restrictions on the amount of distributions allowed to be made by our subsidiaries.

- Our utility subsidiaries are generally limited in the amount of dividends allowed by state regulatory authorities they can pay the utility holding company and also may have further restrictions under the Federal Power Act. As of March 31, 2012, the restricted net assets at our Electric and Gas Utilities were approximately $81.4 million.

- As required by the covenants in the Black Hills Wyoming project financing, Black Hills Non-regulated Holdings has restricted equity of at least $100.0 million. In addition, Black Hills Wyoming holds $9.0 million of restricted cash associated with the project financing requirements.

Future Financing Plans

We have substantial capital expenditures planned in 2012, which primarily include construction of additional utility generation to serve Black Hills Power and Cheyenne Light customers, wind generation to meet renewable standards in Colorado, environmental upgrades and replacements to existing generation to meet governmental pollution mandates and potential capital deployment in oil and gas drilling to prove-up reserves. Our capital requirements are expected to be financed through a combination of operating cash flows, borrowings on our Revolving Credit Facility, term loans and long-term financings and equity issuances.

In 2012, we may consider refinancing the $225 million of debt due in 2013 and, we are evaluating financing options that include senior unsecured notes, first mortgage bonds, term loans and project financings. We intend to maintain a consolidated debt-to-capitalization level in the range of 50% to 55%; however, due to capital projects, we may exceed this level on a temporary basis. We anticipate that our existing credit capacity and available cash will be sufficient to fund our working capital needs and our maintenance capital requirements.

Hedges and Derivatives

Interest Rate Swaps

We have entered into floating-to-fixed interest rate swap agreements to reduce our exposure to interest rate fluctuations.

We have interest rate swaps with a notional amount of $250 million that are not designated as hedge instruments. Accordingly, mark-to-market changes in value on these swaps are recorded within the Condensed Consolidated Statements of Income and Comprehensive Income. For the three months ended March 31, 2012, we recorded $12.0 million pre-tax unrealized mark-to-market non-cash gains on the swaps. The mark-to-market value on these swaps was a liability of $83.9 million at March 31, 2012. Subsequent mark-to-market adjustments could have a significant impact on our results of operations. A 0.01% move in the interest rate curves over the term of the swaps would have a pre-tax impact of approximately $0.3 million. These swaps are for terms of 7 and 17 years and have amended early termination dates ranging from December 15, 2012 to December 16, 2013. We anticipate extending these agreements upon the early termination dates and have continued to maintain these swaps in anticipation of our upcoming financing needs, particularly as they relate to our planned capital requirements to build gas-fired power generation facilities to serve our Black Hills Power and Cheyenne Light customers, and because of our upcoming holding company debt maturities, which are $225 million and $250 million in years 2013 and 2014, respectively. Alternatively, we may choose to cash settle these swaps at fair value prior to the early termination dates, or unless these dates are extended, we will cash settle these swaps for an amount equal to their fair values on the termination dates.

In addition, we have $150 million notional amount floating-to-fixed interest rate swaps with a maximum remaining term of 4.75 years. These swaps have been designated as cash flow hedges, and accordingly their mark-to-market adjustments are recorded in Accumulated other comprehensive income (loss) on the accompanying Condensed Consolidated Balance Sheets. The mark-to-market value of these swaps was a liability of $25.2 million at March 31, 2012.

There have been no other material changes in our financing transactions and short-term liquidity from those reported in Item 7 of our 2011 Annual Report on Form 10-K filed with the SEC.

Credit Ratings

Credit ratings impact our ability to obtain short- and long-term financing, the cost of such financing, and vendor payment terms including collateral requirements. As of March 31, 2012, our senior unsecured credit ratings, as assessed by the three major credit rating agencies, were as follows:

Rating Agency	Rating	Outlook
Fitch	BBB-	Stable
Moody's	Baa3	Stable
S&P	BBB-	Stable

In addition, as of March 31, 2012, Black Hills Power's first mortgage bonds were rated as follows:

Rating Agency	Rating	Outlook
Fitch	A-	Stable
Moody's	A3	Stable
S&P	BBB+	Stable

Capital Requirements

Actual and forecasted capital requirements for maintenance capital and development capital are as follows (in thousands):

	Expenditures for the Three Months Ended March 31, 2012	Total 2012 Planned Expenditures	Total 2013 Planned Expenditures	Total 2014 Planned Expenditures
Utilities:				
Electric Utilities (1)	$29,513	$221,600	$304,500	$187,000
Gas Utilities	5,318	46,000	54,700	43,800
Non-regulated Energy:				
Oil and Gas (2)	16,444	86,500	83,900	122,600
Power Generation	3,433	2,900	4,900	6,700
Coal Mining	2,202	18,800	7,200	10,800
Corporate	4,856	10,300	6,000	4,700
	$61,766	$386,100	$461,200	$375,600

(1) Planned expenditures in 2012 and 2013 for the proposed 88 MW of gas-fired generation at Colorado Electric have been removed from the forecasted expenditures reported in our Annual Report filed on Form 10-K as a result of the denial of our request for a CPCN.

(2) Capital expenditures at our Oil and Gas Segment are driven by economics and may vary depending on the pricing environment for crude oil and natural gas. Forecasted expenditures shown above for the Oil and Gas segment have been decreased from the amounts reported in our Annual Report filed on Form 10-K due to delaying our gas drilling program as a result of lower natural gas prices.

We continually evaluate all of our forecasted capital expenditures, and if determined prudent, we may defer some of these expenditures for a period of time. Future projects are dependent upon the availability of attractive economic opportunities, and as a result, actual expenditures may vary significantly from forecasted estimates.

Contractual Obligations

There have been no significant changes to contractual obligations from those previously disclosed in Note 19 of our Notes to the Consolidated Financial Statements in our 2011 Annual Report on Form 10-K.

Guarantees

There have been no significant changes to guarantees from those previously disclosed in Note 20 of our Notes to the Consolidated Financial Statements in our 2011 Annual Report on Form 10-K.

New Accounting Pronouncements

Other than the pronouncements reported in our 2011 Annual Report on Form 10-K filed with the SEC and those discussed in Note 2 of the Notes to Condensed Consolidated Financial Statements in this Quarterly Report on Form 10-Q, there have been no new accounting pronouncements that are expected to have a material effect on our financial statements.

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FORWARD-LOOKING INFORMATION

This Quarterly Report on Form 10-Q contains forward-looking information. All statements, other than statements of historical fact, included in this report that address activities, events, or developments that we expect, believe or anticipate will or may occur in the future are forward-looking statements. These forward-looking statements are based on assumptions which we believe are reasonable based on current expectations and projections about future events and industry conditions and trends affecting our business. Forward-looking information involves risks and uncertainties, and certain important factors can cause actual results to differ materially from those anticipated. In some cases, forward-looking statements can be identified by terminology such as "may," "will," "could," "should," "expects," "plans," "anticipates," "believes," "estimates," "projects," "predicts," "potential," or "continue" or the negative of these terms or other similar terminology. There are various factors that could cause actual results to differ materially from those suggested by the forward-looking statements; accordingly, there can be no assurance that such indicated results will be realized. The factors which may cause our results to vary significantly from our forward-looking statements include the risk factors described in Item 1A of our 2011 Annual Report on Form 10-K, Part II, Item 1A of this Quarterly Report on Form 10-Q, and other reports that we file with the SEC from time to time, and the following:

- We anticipate that our existing credit capacity and available cash will be sufficient to fund our working capital needs and our maintenance capital requirements. Some important factors that could cause actual results to differ materially from those anticipated include:

- Our access to revolving credit capacity depends on maintaining compliance with loan covenants. If we violate these covenants, we may lose revolving credit capacity and therefore may not have sufficient cash available for our peak winter needs and other working capital requirements, and our forecasted capital expenditure requirements.

- Counterparties may default on their obligations to supply commodities, return collateral to us, or otherwise meet their obligations under commercial contracts, including those designed to hedge against movements in commodity prices.

- We expect to fund a portion of our forecasted capital requirements through a combination of long-term debt and equity issuances however capital market conditions and market uncertainties related to interest rates may affect our ability to raise capital on favorable terms.

- We expect to make approximately $386.1 million, $461.2 million and $375.6 million of capital expenditures in 2012, 2013 and 2014, respectively. Some important factors that could cause actual expenditures to differ materially from those anticipated include:

- The timing of planned generation, transmission or distribution projects for our Utilities Group is influenced by state and federal regulatory authorities and third parties. The occurrence of events that impact (favorably or unfavorably) our ability to make planned or unplanned capital expenditures could cause our forecasted capital expenditures to change.

- Forecasted capital expenditures associated with our Oil and Gas segment are driven, in part, by current product prices. Changes in crude oil and natural gas prices may cause us to change our planned capital expenditures related to our oil and gas operations.

- Our ability to complete our planned capital expenditures associated with our Oil and Gas segment may be impacted by our ability to obtain necessary drilling permits, and other necessary contract services and equipment such as drilling rigs, hydraulic fracturing services and other support services. Our plans may also be negatively impacted by weather conditions and existing or proposed regulations, including possible hydraulic fracturing regulations.

- Our ability to complete the planning, permitting, construction, start-up and operation of power generation facilities in a cost-efficient and timely manner.

- We expect contributions to our defined benefit pension plans to be approximately $0.0 million and $4.5 million for the remainder of 2012 and for 2013, respectively. Some important factors that could cause actual contributions to differ materially from anticipated amounts include:

- The actual value of the plans' invested assets.

- The discount rate used in determining the funding requirement.

- The outcome of pending labor negotiations relating to benefit participation of our collective bargaining agreements.

- We expect the goodwill related to our utility assets to fairly reflect the long-term value of stable, long-lived utility assets. Some important factors that could cause us to revisit the fair value of this goodwill include:

- A significant and sustained deterioration of the market value of our common stock.

- Negative regulatory orders, condemnation proceedings or other events that materially impact our Utilities Groups' ability to generate sufficient stable cash flow over an extended period of time.

- The effects of changes in the market including significant changes in the risk-adjusted discount rate or growth rates.

- The timing, volatility, and extent of changes in energy and commodity prices, supply or volume, the cost and availability of transportation of commodities, changes in interest rates, and the demand for our services, any of which can affect our earnings, our financial liquidity and the underlying value of our assets, including the possibility that we may be required to take future impairment charges under the SEC's full cost ceiling test for natural gas and crude oil reserves.

- Federal and state laws concerning climate change and air emissions, including emission reduction mandates, carbon emissions and renewable energy portfolio standards, may materially increase our generation and production costs and could render some of our generating units uneconomical to operate and maintain or which could mandate or require closure of one or more of our generating units.

- We are evaluating financing options including senior notes, first mortgage bonds, term loans, project financing and equity issuance. Some important factors that could cause actual results to differ materially from those anticipated include:

- Our ability to access the bank loan and debt and equity capital markets depends on market conditions beyond our control. If the capital markets deteriorate, we may not be able to permanently refinance some short-term debt and fund our capital projects on reasonable terms, if at all.

- Our ability to raise capital in the debt capital markets depends upon our financial condition and credit ratings, among other things. If our financial condition deteriorates unexpectedly, or our credit ratings are lowered, we may not be able to refinance some short-term debt and fund our power generation projects on reasonable terms, if at all.

ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Utilities

Our utility customers are exposed to the effect of volatile natural gas prices. We produce, purchase and distribute power in four states and purchase and distribute natural gas in five states, and we utilize natural gas as fuel at our Electric Utilities. All of our gas utilities have PGA provisions that allow them to pass the prudently-incurred cost of gas and services through to the customer. To the extent that gas prices are higher or lower than amounts in our current billing rates, adjustments are made on a periodic basis to true-up billed amounts to match the actual natural gas cost we incurred. These adjustments are subject to periodic prudence reviews by the state utility commissions. We have ECA mechanisms in South Dakota, Colorado, Wyoming and Montana for our electric utilities that serve a purpose similar to the PGAs for our gas utilities. To the extent that our fuel and purchased power energy costs and transmission costs are higher or lower than the energy cost built into our tariffs, the difference (or a portion thereof) is passed through to the customer.

As allowed or required by state utility commissions, we have entered into certain exchange-traded natural gas futures, options and basis swaps to reduce our customers' underlying exposure to volatility of natural gas prices. These transactions are considered derivatives and are marked-to-market. Gains or losses, as well as option premiums on these transactions, are recorded in Regulatory assets or Regulatory liabilities. Once settled, the gains and losses are passed on to our customers through the PGA.

The fair value of our Utilities Group's derivative contracts is summarized below (in thousands):

	March 31, 2012	December 31, 2011	March 31, 2011
Net derivative (liabilities) assets	$(14,816)	$(16,676)	$(2,455)
Cash collateral	17,651	19,416	3,720
	$2,835	$2,740	$1,265

Activities Other Than Trading

We have entered into agreements to hedge a portion of our estimated 2012, 2013 and 2014 natural gas and crude oil production from the Oil and Gas segment. The hedge agreements in place at March 31, 2012 were as follows:

Natural Gas

Location	Transaction Date	Hedge Type	Term	Volume (MMBtu/day)	Price
San Juan El Paso	3/19/2010	Swap	04/12 - 06/12	7,000	$5.27
CIG	3/19/2010	Swap	04/12 - 06/12	1,500	$5.17
NWR	3/19/2010	Swap	04/12 - 06/12	1,500	$5.20
AECO	3/19/2010	Swap	04/12 - 06/12	250	$5.15
San Juan El Paso	10/31/2011	Swap	04/12 - 06/12	1,000	$3.58
San Juan El Paso	2/22/2012	Swap	04/12 - 10/12	2,500	$2.71
San Juan El Paso	6/28/2010	Swap	07/12 - 09/12	3,500	$5.19
NWR	6/28/2010	Swap	07/12 - 09/12	1,500	$5.01
CIG	6/28/2010	Swap	07/12 - 09/12	1,500	$4.98
San Juan El Paso	4/19/2011	Swap	07/12 - 09/12	2,000	$4.45
San Juan El Paso	10/31/2011	Swap	07/12 - 09/12	1,000	$3.77
CIG	2/18/2011	Swap	10/12 - 12/12	500	$4.42
San Juan El Paso	2/18/2011	Swap	10/12 - 12/12	2,500	$4.46
NWR	2/18/2011	Swap	10/12 - 12/12	1,000	$4.44
San Juan El Paso	4/19/2011	Swap	10/12 - 12/12	2,000	$4.62
San Juan El Paso	10/31/2011	Swap	10/12 - 12/12	1,000	$3.94
San Juan El Paso	12/9/2011	Swap	10/12 - 12/12	1,000	$3.59
San Juan El Paso	2/22/2012	Swap	11/2012	2,500	$3.03
San Juan El Paso	2/22/2012	Swap	12/2012	2,500	$3.32
San Juan El Paso	4/19/2011	Swap	01/13 - 03/13	2,500	$5.03
San Juan El Paso	6/6/2011	Swap	01/13 - 03/13	2,500	$5.18
San Juan El Paso	10/31/2011	Swap	01/13 - 03/13	1,000	$4.32
San Juan El Paso	12/9/2011	Swap	01/13 - 03/13	1,000	$3.91
NWR	12/9/2011	Swap	01/13 - 03/13	1,000	$4.02
San Juan El Paso	4/19/2011	Swap	04/13 - 06/13	2,500	$4.64
San Juan El Paso	10/31/2011	Swap	04/13 - 06/13	1,000	$4.13
San Juan El Paso	12/9/2011	Swap	04/13 - 06/13	1,000	$3.77
NWR	12/9/2011	Swap	04/13 - 06/13	1,000	$3.83
San Juan El Paso	10/31/2011	Swap	07/13 - 09/13	1,000	$4.27
San Juan El Paso	12/9/2011	Swap	07/13 - 09/13	1,000	$3.95
NWR	12/9/2011	Swap	07/13 - 09/13	1,000	$3.97
San Juan El Paso	12/9/2011	Swap	10/13 - 12/13	1,000	$4.05
NWR	12/9/2011	Swap	10/13 - 12/13	1,000	$4.08

Crude Oil

Location	Transaction Date	Hedge Type	Term	Volume (Bbls/month)	Price
NYMEX	3/4/2011	Swap	01/12 - 12/12	2,000	$104.60
NYMEX	3/19/2010	Swap	04/12 - 06/12	5,000	$84.00
NYMEX	3/31/2010	Put	04/12 - 06/12	5,000	$75.00
NYMEX	5/13/2010	Swap	04/12 - 06/12	5,000	$87.85
NYMEX	8/17/2010	Swap	04/12 - 06/12	3,000	$82.60
NYMEX	6/28/2010	Swap	07/12 - 09/12	5,000	$83.80
NYMEX	8/17/2010	Swap	07/12 - 09/12	5,000	$82.85
NYMEX	9/16/2010	Swap	07/12 - 09/12	5,000	$84.60
NYMEX	4/20/2011	Swap	07/12 - 06/13	2,000	$106.80
NYMEX	10/17/2011	Put	07/12 - 09/13	2,000	$80.00
NYMEX	10/17/2011	Call	07/12 - 09/13	2,000	$95.00
NYMEX	11/9/2010	Swap	10/12 - 12/12	5,000	$91.10
NYMEX	1/6/2011	Swap	10/12 - 12/12	5,000	$93.40
NYMEX	2/17/2011	Swap	10/12 - 03/13	5,000	$97.85
NYMEX	1/20/2011	Swap	01/13 - 03/13	5,000	$94.20
NYMEX	3/4/2011	Swap	01/13 - 03/13	3,000	$103.35
NYMEX	11/2/2011	Call	01/13 - 12/13	3,000	$100.00
NYMEX	11/2/2011	Put	01/13 - 12/13	3,000	$77.50
NYMEX	6/3/2011	Swap	04/13 - 06/13	5,000	$100.90
NYMEX	7/27/2011	Swap	04/13 - 06/13	5,000	$102.72
NYMEX	12/9/2011	Call	04/13 - 06/13	2,000	$100.50
NYMEX	12/9/2011	Put	04/13 - 06/13	2,000	$90.00
NYMEX	10/17/2011	Swap	07/13 - 09/13	2,000	$88.50
NYMEX	12/9/2011	Call	07/13 - 09/13	3,000	$99.00
NYMEX	12/9/2011	Put	07/13 - 09/13	3,000	$90.00
NYMEX	7/27/2011	Swap	07/13 - 09/13	5,000	$102.75
NYMEX	2/22/2012	Swap	07/13 - 09/13	5,000	$103.02
NYMEX	12/9/2011	Call	10/13 - 12/13	4,000	$98.00
NYMEX	12/9/2011	Put	10/13 - 12/13	4,000	$90.00
NYMEX	2/22/2012	Swap	10/13 - 12/13	5,000	$101.75
NYMEX	2/22/2012	Swap	01/14 - 03/14	10,000	$100.20

Financing Activities

We engage in activities to manage risks associated with changes in interest rates. We have entered into floating-to-fixed interest rate swap agreements to reduce our exposure to interest rate fluctuations associated with our floating rate debt obligations. As of March 31, 2012, we had $150.0 million of notional amount floating-to-fixed interest rate swaps, having a maximum term of 4.75 years. These swaps have been designated as hedges in accordance with accounting standards for derivatives and hedges and accordingly their mark-to-market adjustments are recorded in Accumulated other comprehensive income (loss) on the Condensed Consolidated Balance Sheets.

We also have interest rate swaps with a notional amount of $250.0 million which were entered into for the purpose of hedging interest rate movements that would impact long-term financings that were originally expected to occur in 2008. The swaps were originally designated as cash flow hedges and the mark-to-market value was recorded in Accumulated other comprehensive income (loss) on the Condensed Consolidated Balance Sheets. Based on credit market conditions that transpired during the fourth quarter of 2008, we determined it was probable that the forecasted long-term debt financings would not occur in the time period originally specified and, as a result, the swaps were no longer effective hedges and the hedge relationships were de-designated. Mark-to-market adjustments on the swaps are now recorded within the Condensed Consolidated Statements of Income and Other Comprehensive Income. For the three months ended March 31, 2012, we recorded pre-tax unrealized mark-to-market gains of $12.0 million. For the three months ended March 31, 2011, we recorded pre-tax unrealized mark-to-market gains of $5.5 million. These swaps are 7 and 17 year swaps which have amended early termination dates ranging from December 2012 to December 2013.

We have continued to maintain these swaps in anticipation of our upcoming financing needs, particularly our upcoming holding company debt maturities, which are $225 million and $250 million in years 2013 and 2014, respectively. Alternatively, we may choose to cash settle these swaps at fair value prior to the early termination dates, or unless these dates are extended, we will cash settle these swaps for an amount equal to their fair values on the stated termination dates.

Further details of the swap agreements are set forth in Note 13 of the Notes to the Condensed Consolidated Financial Statements in this Quarterly Report on Form 10-Q.

As of March 31, 2012, December 31, 2011 and March 31, 2011, our interest rate swaps and related balances were as follows (dollars in thousands):

	March 31, 2012		December 31, 2011		March 31, 2011	
	Designated Interest Rate Swaps	De-designated Interest Rate Swaps*	Designated Interest Rate Swaps	De-designated Interest Rate Swaps*	Designated Interest Rate Swaps	De-designated Interest Rate Swaps*
Notional	$150,000	$ 250,000	$150,000	$ 250,000	$150,000	$ 250,000
Weighted average fixed interest rate	5.04 %	5.67 %	5.04 %	5.67 %	5.04 %	5.67 %
Maximum terms in years	4.75	1.75	5.00	2.00	5.75	0.75
Derivative liabilities, current	$6,777	$ 66,708	$6,513	$ 75,295	$6,769	$ 48,515
Derivative liabilities, non-current	$18,441	$ 17,237	$20,363	$ 20,696	$12,955	$ —
Pre-tax accumulated other comprehensive loss included in Condensed Consolidated Balance Sheets	$(25,218)	$ —	$(26,876)	$ —	$(19,724)	$ —
	$—	$ 12,045	$—	$ (42,010)	$—	$ 5,465

Pre-tax (loss) gain included in Condensed Consolidated Statements of Income and Comprehensive Income						
Cash collateral receivable (payable) included in accounts receivable	$—	$ —	$—	$ —	$—	$ —

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* Maximum terms in years for our de-designed interest rate swaps reflect the amended early termination dates. If the early termination dates are not extended, the swaps will require cash settlement based on the swap value on the termination date. When extended annually, de-designated swaps totaling $100 million terminate in 7 years and de-designated swaps totaling $150 million terminate in 17 years.

Based on March 31, 2012 market interest rates and balances for our designated interest rate swaps, a loss of approximately $6.8 million would be realized and reported in pre-tax earnings during the next 12 months. Estimated and realized losses will change during the next 12 months as market interest rates change.

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ITEM 4. CONTROLS AND PROCEDURES

This section should be read in conjunction with Item 9A, "Controls and Procedures" included in our Annual Report on Form 10-K for the year ended December 31, 2011.

Our Chief Executive Officer and Chief Financial Officer evaluated the effectiveness of our disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) of the Securities Exchange Act of 1934 (Exchange Act)) as of March 31, 2012 and concluded that, because of the material weakness in our internal control over financial reporting related to accounting for income taxes as previously disclosed in Item 9A, “Controls and Procedures” in our Annual Report on Form 10-K for the year ended December 31, 2011, our disclosure controls and procedures were not effective as of March 31, 2012. Additional review, evaluation and oversight have been undertaken to ensure our unaudited Condensed Consolidated Financial Statements were prepared in accordance with generally accepted accounting principles and as a result, our management, including our Chief Executive Officer and Chief Financial Officer, have concluded that the Condensed Consolidated Financial Statements in this Form 10-Q fairly present in all material respects our financial position, results of operations and cash flows for the periods presented in conformity with accounting principles generally accepted in the United States.

As discussed in our 2011 Annual Report on Form 10-K, management concluded that while we had appropriately designed control procedures for income tax accounting and disclosures, the existence of non-routine transactions, insufficient tax resources, and ineffective communications between the tax department and Controller organization caused us to poorly execute the controls for evaluating and recording income taxes. Management has developed and is implementing a remediation plan to address this material weakness in internal controls surrounding accounting for income taxes. Key aspects of the remediation plan include enhancing resources and skill sets and implementing formal periodic meetings among the Chief Financial Officer, Controller and the tax department.

While we concluded our internal controls surrounding income taxes were not effective as of March 31, 2012, we are remediating the material weakness and will continue to implement our remediation plan and track our performance against the plan.

During the quarter ended March 31, 2012 there have been no other changes in our internal control over financial reporting that have materially affected or are reasonably likely to materially affect our internal control over financial reporting.

BLACK HILLS CORPORATION

Part II — Other Information

ITEM 1. Legal Proceedings

For information regarding legal proceedings, see Note 19 in Item 8 of our 2011 Annual Report on Form 10-K and Note 16 in Item 1 of Part I of this Quarterly Report on Form 10-Q, which information from Note 16 is incorporated by reference into this item.

ITEM 1A. Risk Factors

There are no material changes to the Risk Factors previously disclosed in Item 1A of Part I in our Annual Report on Form 10-K for the year ended December 31, 2011.

ITEM 2. Unregistered Sales of Equity Securities and Use of Proceeds

Issuer Purchases of Equity Securities

Period	Total Number of Shares Purchased[(1)]	Average Price Paid per Share	Total Number of Shares Purchased as Part of Publicly Announced Plans for Programs	Maximum Number (or Approximate Dollar Value) of Shares That May Yet Be Purchased Under the Plans or Programs
January 1, 2012 - January 31, 2012	8,854	$33.58	—	—
February 1, 2012 - February 29, 2012	22,180	$34.77	—	—
March 1, 2012 - March 31, 2012	—	$—	—	—
Total	31,034	$34.43	—	—

(1) Shares were acquired from certain officers and key employees under the share withholding provisions of the Omnibus Incentive Plan for the payment of taxes associated with the vesting of shares of restricted stock.

ITEM 4. Mine Safety Disclosures

Information concerning mine safety violations or other regulatory matters required by Sections 1503(a) of Dodd-Frank is included in Exhibit 95 of this Quarterly Report on Form 10-Q.

ITEM 5. Other Information

None.

ITEM 6. Exhibits

Exhibit 10.1	Stock Purchase Agreement by and between Twin Eagle Resource Management, LLC and Black Hills Non-regulated Holdings LLC for the purchase of capital stock of Enserco Energy Inc., dated January 18, 2012.
Exhibit 10.2 *	Credit Agreement, dated February 1, 2012, among Black Hills Corporation, as Borrower, U.S. Bank, National Association, in its capacity as administrative agent for the Banks under the Credit Agreement, and as a Bank, and the other banks party thereto (filed as Exhibit 10 to the Registrant's Form 8-K filed on February 3, 2012).
Exhibit 31.1	Certification of Chief Executive Officer pursuant to Rule 13a - 14(a) of the Securities Exchange Act of 1934, as adopted pursuant to Section 302 of the Sarbanes - Oxley Act of 2002.
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Exhibit 95	Mine Safety and Health Administration Safety Data
Exhibit 101	Financial Statements for XBRL Format

* Previously filed as part of the filing indicated and incorporated by reference herein.

BLACK HILLS CORPORATION

Signatures

Pursuant to the requirements of the Securities Exchange Act of 1934, the Registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

BLACK HILLS CORPORATION

/s/ David R. Emery
David R. Emery, Chairman, President and
Chief Executive Officer

/s/ Anthony S. Cleberg
Anthony S. Cleberg, Executive Vice President and
Chief Financial Officer

Dated: May 4, 2012

EXHIBIT INDEX

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